PB89-139695

Proceedings: 1987 Joint Symposium on Stationary Source Combustion NOx Control Held in New Orleans, Louisiana on March 23-26, 1987. Volume 1

Radian Corp., Research Triangle Park, NC

Prepared for

Electric Power Research Inst., Palo Alto, CA

Dec 88

U.S. Department of Commerce
National Technical Information Service
NTIS

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA/600/9-88/026a	2.	3. RECIPIENT'S ACCESSION NO. PB89 139695/AS
4. TITLE AND SUBTITLE Proceedings: 1987 Joint Symposium on Stationary Combustion NO_x Control, New Orleans, LA, March 1987; Volume 1		5. REPORT DATE December 1988
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) B. B. Emmel, Compiler		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Radian Corporation P. O. Box 13000 Research Triangle Park, North Carolina 27709		10. PROGRAM ELEMENT NO.
		11. CONTRACT/GRANT NO. 68-02-3994, Task 93 2154-12 (EPRI)
12. SPONSORING AGENCY NAME AND ADDRESS **EPA, Office of Research and Development*** **Air and Energy Engineering Research Laboratory** **Research Triangle Park, NC 27711**		13. TYPE OF REPORT AND PERIOD COVERED Proceedings; March 1987
		14. SPONSORING AGENCY CODE **EPA/600/13**

15. SUPPLEMENTARY NOTES AEERL project officer is James D. Kilgroe, Mail Drop 65, 919/541-2854. EPA-600/9-86-021a and -021b document the previous symposium on this topic: May 1985 in Boston, MA. (*)Cosponsor: EPRI, Palo Alto, CA 94304.

16. ABSTRACT The two-volume proceedings document the 1987 Joint (EPA and EPRI) Symposium on Stationary Combustion NOx Control, held March 23-26, 1987, in New Orleans, LA. The 49 presentations covered: low-NOx combustion developments (e.g., reburning and burner design modifications); coal-, oil-, and gas-fired boiler applications; flue gas treatment processes; fundamental combustion studies; and industrial and commercial applications. Also presented were manufacturers' updates of commercially available technology and an overview of environmental issues involving NOx control. Attendees represented 14 nations. Volume 1 covers Sessions I (background and environmental issues), II (low-NOx combustion development), III (manufacturers' update of commercially available technology), and IV (coal-fired boiler applications). Volume 2 covers Sessions Va (flue gas treatment), Vb (fundamental combustion studies), VI (cyclone-fired boilers), VIIa (oil- and gas-fired boilers), and VIIb (industrial and commercial applications).

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Boilers	Pollution Control	13B
Nitrogen Oxides		Stationary Sources	07B
Combustion		Reburning	21B
Flue Gases			
Fossil Fuels			21D
Burners			13A

18. DISTRIBUTION STATEMENT **Release to Public**	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 497
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (9-73)

PB89-139695

EPA/600/9-88/026a
December 1988

PROCEEDINGS:

1987 JOINT SYMPOSIUM ON STATIONARY SOURCE COMBUSTION NO_X CONTROL

(New Orleans, LA, March 1987)
Volume 1

Compiled by

Barbara Emmel
Radian Corporation
Post Office Box 13000
Research Triangle Park, North Carolina 27709

EPA Contract 68-02-3994, Work Assignment 93
EPRI Contract 2154-12

EPA Project Officer:
James D. Kilgroe

U. S. Environmental Protection Agency
Air and Energy Engineering Research Laboratory
Research Triangle Park, North Carolina 27711

EPRI Project Manager:
David Eskinazi

Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, California 93404

AIR AND ENERGY ENGINEERING RESEARCH LABORATORY
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

REPRODUCED BY
U.S. DEPARTMENT OF COMMERCE
NATIONAL TECHNICAL INFORMATION SERVICE
SPRINGFIELD, VA. 22161

NOTICE

This document has been reviewed in accordance with U.S. Environmental Protection Agency policy and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

PREFACE

The 1987 Joint Symposium on Stationary Combustion NO_x Control was held March 23 - 26, 1987, in New Orleans, Louisiana. This symposium, jointly sponsored by EPRI and EPA, was the fourth of its kind devoted solely to the discussion of control of NO_x emissions from stationary sources. Specific topics discussed included the low-NO_x combustion developments such as reburning and burner design modifications, coal-, oil-, and gas-fired boilers applications, flue gas treatment processes, fundamental combustion studies, and industrial and commercial applications. Also presented were manufacturers' updates of commercially available technology and an overview of environmental issues involving NO_x control.

The 4-day meeting was attended by persons from 14 nations. Forty-nine papers were presented by EPRI and EPA staff members, utility company representatives, boiler and related equipment manufacturers, research and development groups, and university representatives.

Symposium cochairpersons were David Eskinazi, Project Manager in the Air Quality Control Program of EPRI's Coal Combustion Systems Division; and James D. Kilgroe, Mechanical Engineer in the Combustion Research Branch of the EPA's Air and Energy Engineering Research Laboratory. Each of the cochairpersons made brief introductory remarks. Congressman Billy Tauzin of Louisiana delivered the keynote address. Written manuscripts were not prepared for the introductory remarks or keynote address; therefore, they are not published herein.

The Proceedings of the 1987 Joint Symposium have been compiled in two volumes. Volume 1 contains papers from the following sessions:

- Session I: Background and Environmental Issues
- Session II: Low-NO_x Combustion Development
- Session III: Manufacturers' Update of Commercially Available Technology
- Session IV: Coal-Fired Boiler Applications

Papers from the following sessions are contained in Volume 2:

- Session Va: Flue Gas Treatment
- Session Vb: Fundamental Combustion Studies
- Session VI: Cyclone-Fired Boilers
- Session VIIa: Oil- and Gas-Fired Boilers
- Session VIIb: Industrial and Commercial Applications

Also included in both volumes is an Appendix listing the Symposium attendees.

The assistance of Holly Rossi, Radian Corporation, in compiling these Proceedings is gratefully acknowledged.

CONTENTS

VOLUME 1

Paper Page

"Opening Remarks," J. Kilgroe and D. Eskinazi

"Keynote Address," B. Tauzin

SESSION I: BACKGROUND AND ENVIRONMENTAL ISSUES
Chairman, E. Plyler, EPA

1A "The New Environmental Agenda and the Coming Commitment to NO_x Controls," R. Ayres.................................... 1-1

1B "Decline of Boreal Montane Forest Ecosystems in Central Europe and the Eastern North America - Links to Air Pollution and the Deposition of Nitrogen Compounds," R. Bruck.................... 2-1

1C "An Overview of Environmental Issues Related to Nitrogen Oxides in the Atmosphere," C. Hakkarinen...................... 3-1

1D "The Role of Nitrous Oxide (N_2O) in Global Climate Change and Stratospheric Ozone Depletion," D. Tirpak.................. 4-1

1E "Overview of Recent Developments in NO_x Control in Europe," O. Rentz and R. Leibfritz.................................. 5-1

SESSION II: LOW-NO_x COMBUSTION DEVELOPMENT
Chairman, R. Hall, EPA

2A "Large-Scale Testing and Development of the B&W Low-NO_x Cell Burner," M. Clark, A. LaRue, A. Liang, and D. Eskinazi..... 6-1

2B "Low-NO_x Developments on an Integrated Combustion and Environmental Test Facility," J. Vatsky........................ 7-1

2C "Development of Overfire Air Design Guidelines for Front-Fired Boilers," R. Lisauskas, R. Afonso, and D. Eskinazi............. 8-1

2D "Furnace Design and Application on Low-NO_x Pulverized Coal Combustion," T. Kiga, S. Miyamae, K. Makino, and H. Ikebe....... 9-1

2E "Gas Reburning-Sorbent Injection - A Combined NO_x/SO_x Control Technology," W. Bartok, B. Folsom, and R. Kurzynske............ 10-1

CONTENTS (Continued)

Paper Page

2F "Pilot-Scale Studies on the Application of Reburning for NO_x Control," J. McCarthy, S. Chen, W. Seeker, and D. Pershing 11-1

2G "Reburning with Low and Medium Btu Gases," S. Bortz and G. Offen 12-1

SESSION III: MANUFACTURERS' UPDATE OF COMMERCIALLY AVAILABLE TECHNOLOGY
Chairman, J. Kilgroe, EPA

3A "1987 Update on NO_x Emissions Control Technologies at Combustion Engineering," M. McCartney, A. Kokkinos, R. Lewis, T. Hellewell, and M. Cohen 13-1

3B "Update of NO_x Control Technologies at Riley Stoker," C. McHale and R. Lisauskas 14-1

3C "Industrial and Utility Boiler NO_x Control Update," J. Vatsky 15-1

3D "NO_x Control Update - 1987," A. LaRue and P. Cioffi 16-1

SESSION IV: COAL-FIRED BOILER APPLICATIONS
Chairman, D. Eskinazi, EPRI

4A "The Federal Clean Coal Program," J. Siegel 17-1

4B "Development Status of B&W's Second Generation Low-NO_x Burner--The XCL Burner," A. LaRue, M. Acree, and C. Masser 18-1

4C "Reductions in NO_x Emissions from a 500 MW Corner-Fired Boiler," J. Allen, W. Brooks, N. Burdett, F. Clarke, and G. Foley 19-1

4D "Application of Mitsubishi 'Advanced MACT' In-Furnace NO_x Removal Process at Taio Paper Co., Ltd., Mishima Mill No. 18 Boiler," M. Araoka, A. Iwanaga, and M. Sakai 20-1

4E "Operating Experiences of Coal-Fired Utility Boilers Using Hitachi NO_x Reduction Burners," T. Narita, F. Koda, T. Masai, S. Morita, and S. Azuhata 21-1

CONTENTS (Continued)

Paper Page

4F "Long-Term Versus Short-Term Data Analysis Methodologies," L. Smith, W. Pitts, R. Rush, and T. Flora....................... 22-1

4G "Engineering and Economic Analysis of Retrofit Low-NO_x Combustion Systems," R. Lisauskas, R. Snodgrass, S. Johnson, and D. Eskinazi... 23-1

4H "The Influence of Fuel Properties and Boiler Design and Operation on NO_x Emissions," J. Pohl, G. Dusatko, P. Orban, and R. McGraw.................................... 24-1

VOLUME 2

SESSION Va: FLUE GAS TREATMENT
Chairmen, E. Cichanowicz and J. Maulbetsch, EPRI

5A-1 "Current Status of SCR in Japan," Y. Nakabayashi, R. Abe, and M. Takahashi.. 25-1

5A-2 "Operating Experience with the SCR DeNO_x Plant in Unit 5 of Altbach/Deizisau Power Station," P. Necker.................. 26-1

5A-3 "VKR Full-Scale SCR Experience on Hardcoal-Fired Boilers," K. Goldschmidt... 27-1

5A-4 "Applicability of European SCR Experience to U. S. Utility Operation," E. Cichanowicz and G. Offen........................ 28-1

5A-5 "Comparison of Four Catalysts Used in Selective Catalytic Reduction of NO_x," B. Herrlander................................ 29-1

5A-6 "The Improvement of NH_3 Injection Control System for a Selective Catalytic NO_x Removal System," K. Suyama.............. 30-1

5A-7 "Development of Low Level NH_3 Measuring Method," Y. Nakabayashi, R. Abe, T. Izumi, and M. Takahashi.............. 31-1

5A-8 "Updated Technical and Economic Review of Selective Catalytic NO_x Reduction Systems," J. Damon, P. Ireland, and D. Giovanni... 32-1

CONTENTS (Continued)

Paper Page

SESSION Vb: FUNDAMENTAL COMBUSTION STUDIES
Chairman, J. Mulholland, EPA

5B-1 "Mechanisms of Fixed Nitrogen Reduction in Pulverized Coal Flames," J. Kramlich, T. Lester, and J. Wendt 33-1

5B-2 "The Interplay Between Chemistry and Fluid Mechanics in the Oxidation of Fuel Nitrogen from Pulverized Coal," C. Kruger, G. Haussmann, and S. Krewson 34-1

5B-3 "Reduction of NO_x by Fuel Staging," M. Toqan, J. Teare, J. Beer, L. Radak, and A. Weir 35-1

5B-4 "Fuel Bound Nitrogen Evolution During the Devolatilization and Pyrolysis of Coals of Varying Rank," J. Freihaut, W. Proscia, and D. Seery 36-1

SESSION VI: CYCLONE-FIRED BOILERS
Chairman, G. Offen, EPRI

6A "Feasibility of Reburning for Cyclone Boiler NO_x Control," G. Maringo, M. Acree, H. Farzan, and M. McElroy 37-1

6B "NO_x Control Options for Coal-Fired Cyclone Utility Boilers," R. Thompson, R. Himes, and G. Offen 38-1

6C "TRW Coal Combustor - NO_x Emissions," D. Frey 39-1

SESSION VIIa: OIL- AND GAS-FIRED BOILERS
Chairman, M. McElroy, EPRI

7A-1 "Methanol Dual-Fuel Combustion," A. Weir, L. Radak, E. Danko, and R. Lewis 40-1

7A-2 "Application of Fuel Biasing for NO_x Emission Reductions in Gas-Fired Utility Boilers," G. Quartucy, M. Mansour, and J. Nylander 41-1

7A-3 "NO_x Inventory and Retrofit Assessment," D. Mormile, S. Kerho, S. Hunter, and P. Coffey 42-1

7A-4 "Full-Scale Evaluation of Urea Injection for NO_x Removal," M. Mansour, S. Nahas, G. Quartucy, J. Nylander, H. Kerry, L. Radak, D. Eskinazi, and T. Behrens 43-1

CONTENTS (Continued)

Paper Page

7A-5 "Retrofit Combustion Controls for Gas-Oil-Fired Utility Boilers," W. Pepper, R. Balingit, D. Giovanni, and D. Teixeira........ 44-1

SESSION VIIb: INDUSTRIAL AND COMMERCIAL APPLICATIONS
Chariman, J. Wasser, EPA

7B-1 "Pilot-Scale Tests of a Multistaged Burner Designed for Low-NO_x Emission and High Combustion Efficiency," J. Mulholland and R. Srivastava........ 45-1

7B-2 "Diesel Engine NO_x Control: Selective Catalytic Reduction and Methanol Emulsion," J. Wasser** and R. Perry........ 46-1

7B-3 "The Control of NO_x Emissions from Municipal Solid Waste Incinerators," M. Heap, W. Lanier, and R. Seeker........ 47-1

7B-4 "Nitrogen Oxide Emissions Reduced from Cement Kiln Exhaust Gases by Process Modification," M. May, J. Croom, R. MacMann, J. Phillips, and G. Young........ 48-1

7B-5 "NO_x Formation in a Cement Kiln: Regression Analysis," J. Croom, M. May, G. Young, C. Phillips, and R. MacMann........ 49-1

Appendix A - List of Attendees........ A-1

THE NEW ENVIRONMENTAL AGENDA AND THE COMING COMMITMENT TO NO_x CONTROL

Richard E. Ayres
Senior Attorney
Natural Resources Defense Council
1350 New York Avenue, N.W.
Washington, DC 20005

ABSTRACT

As the recent ideological approach to environmental problems wanes, a new environmental agenda for the remainder of this century is emerging. Controlling nitrogen oxides emissions from stationary sources -- a pollutant with serious effects on public health, environmental integrity, and esthetic experience -- is part of this agenda. Development of new technology is welcome. But political leaders must not be permitted to use technological change as an excuse for avoiding the use of existing NO_x control technologies now.

I've been asked to discuss the need and prospects for NO_x controls, a "Washington Perspective." I think it is a little like asking the weather man to come to meteorological convention and give his "perspective on the weather." He's supposed to come and act like he knows something that nobody else can understand, prognosticate about what will happen tomorrow, and make sure he leaves himself an out in the (likely) event that his predictions are all wrong.

Well I'll get to my own weather forecasting, but first I would like to take a little longer view at how this symposium fits into the environmental history of our time, and why it is important that we go forward to adopt policies that will require the control of nitrogen oxides emissions.

Over the years, few messages have more consistently been delivered to our government than the message that Americans want air quality that protects their health, their esthetic experiences, and the integrity of the natural environment.

In poll after poll, Americans say overwhelmingly that they want better air quality, believe it can be attained, and are prepared to pay for it.

But the present Administration in Washington has not understood this strong desire.

When Ronald Reagan become President, he appointed officials to head the major environmental agencies who saw the environmental issue primarily in political terms.

They saw issues such as toxic air pollution, urban smog, and acid rain not as problems to be solved, but as ideological struggles between "liberals" and "conservatives." Research and action to solve these problems entered a kind of ice age, from which it is only now beginning to emerge.

Now, as this ideological crusade nears its end, a new and positive atmosphere is beginning to develop.

A new environmental agenda for the remainder of this century is forming -- a pragmatic agenda aimed at practical solutions to the real and serious environmental problems faced by this nation and the entire globe.

More and more, emerging global problems are confirming the insight that animated the creation of the modern environmental agencies, such as the EPA, almost two decades ago. The environment itself reminds and warns us that humans can no longer expect to use the atmosphere as a garbage dump without reaping unacceptable costs in human health and environmental degradation.

In the infancy of the industrial age, man's impact on his environment was small and localized. Now man is engaged in global engineering on vast scale.

Now man must take responsibility for the health of our planet.

Ultimately this is why control of nitrogen oxides is a necessity.

Nitrogen oxides emissions are projected to grow unless new actions are taken. Without new controls, NO_x emissions may overtake sulfur oxides.

The effects of nitrogen oxides in the atmosphere are varied and troubling. NO_x plays an important part in the formation of ozone ("smog") pollution that blankets large parts of our nation in concentrations unhealthy to breathe.

According to EPA, more than 60 metropolitan areas, with a population in excess of 80 million people, will fail to achieve healthful air quality when the present deadline is reached at the end of this year.

Ozone is a serious health problem. Ozone causes increased asthma attacks, reduced pulmonary function, cough and chest discomfort. It it implicated in reduced resistance to lung infections, and structural changes in lung tissue that resemble premature aging of the lung. Associated oxidants (such as PAN) also cause eye irritation.

Ozone can injure and kill crops, forests, and other vegetation. EPA estimates that ozone damage may be causing $1-2 billion in crop losses annually. The Congressional Research Service estimates that the damage to crops and forests may be as high as $4.3 billion annually.

In urban areas, ozone accelerates the deterioration of man-made materials such as rubber, textiles, and paints -- causing additional economic damage.

The need to control nitrogen oxides emissions to reduce ozone has been recognized repeatedly for more than thirty years, from the earliest research on Los Angeles smog to the National Commission on Air Quality's Report to Congress a few years ago.

Epidemiological and animal studies suggest that repeated exposure to nitrogen oxides alone increases susceptibility to respiratory diseases, especially in children. Clinical studies in 1984 have shown that asthmatics experience decreased lung function when exposed to very low levels of NO_x -- 0.3 ppm during moderate exercise.

Nitrogen oxides are major contributors to acid rain, perhaps the leading atmospheric environmental threat facing North Amercia today.

To date, the political debate on acid rain has focused primarily on the contribution of sulfur oxides. But control of nitrogen oxides emissions will also be necessary to deal with the scourge of acid rain.

In 1982, the International Conference on Acidification of the Environment in Stockholm recommended that the "best available technology which is economically feasible should be applied to reduce NO_x emissions from both stationary and mobile sources."

Two years later the International Conference of Ministers on Acid Rain in Ottawa declared that their ten countries were committed to "take measures to decrease effectively the total annual emissions of nitrogen oxides from stationary and mobile sources as soon as possible and at the latest by 1993."

Nitrogen oxides emissions contribute about one-third of the acidity of precipitation to the eastern United States; in the West, over half.

In California, where NO_x emissions exceed sulfur oxides by a factor of four, NO_x-dominated acid fogs have been recorded with a pH reading of an astounding 1.69!

Acid nitrogen compounds play a particularly damaging role in spring, when they dominate the acid compounds released at snowmelt, the most vulnerable period of the life cycle for many aquatic plants and animals.

This led EPA staff to conclude recently that "control of NO_x emissions is necessary to alleviate the (spring) episodic high nitric acid concentrations and the problems associated with them."

Finally, NO_x emissions are responsible for important, if difficult to quantify, degradation of our esthetic experience of the environment. Anyone inclined to scoff at "mere" esthetic effects has not visited Denver, where the infamous "brown cloud" has become a hotly debated political issue in more than one campaign.

Given this long list of ill effects, this nation cannot allow emissions of nitrogen oxides to grow unconstrained to the levels projected.

We must continue to press forward on the kinds of technological developments for controlling NO_x that will be the subject of the many papers presented at this conference.

But we must not allow our political leaders to use the process of technological change as an excuse for avoiding the use of available pollution controls now.

The appeal of this tactic can be seen in the series of "Shamrock Summits" held between the President and his Canadian counterpart, Premier Brian Mulroney.

Next week the two will meet for the third of these events, named in honor of St. Patrick's Day and the Irish heritage of the two leaders.

In previous meetings, Mulroney faced a Canadian public aroused over acid rain damage to Canadian lakes and forests. Reagan opposed doing anything about it.

Rather than pressure his friend, Mulroney agreed to a bit of the old blarney: Reagan would commit to the development of "Clean Coal Technology," and Mulroney would accept that in place of a control program.

But the American government soon welched on this deal, and recently Mulroney complained in public to Vice President Bush -- presumably because he did not want the blarney exposed for what it was. This led the White House to say last week that next year it really would do what it promised a year ago.

Whether Mulroney will insist on a real acid rain control program, or accept the President's promises, remains the key question for the next week's third summit.

Whatever the outcome of the Shamrock Summit, "Clean Coal Technology" must be recognized for what it is -- a political ploy, not an environmental program.

The prospects for the commercial deployment of new technologies for controlling both nitrogen and sulfur oxides depends far more on the adoption of strong domestic legislation to control acid rain.

Necessity, as they say, is the mother of invention. And in the case of acid rain, only regulation can provide the necessity needed to offer an attractive market for new technologies.

So let me now revert to my appointed role as weatherman, and provide some observations on the prospects for acid rain legislation.

First, let me agree with the comments of Congressman Tauzin that acid rain control will become law in this Congress.

Four acid rain bills have been introduced so far in the early days of this 100th Congress, all in the Senate.

Two are significant. Senator Mitchell, chairman of the relevant subcommittee, has introduced a bill that will cut sulfur emissions by 12 million tons and NO_x by about 4 million.

Senator Stafford, ranking Republican, has a bill that would require power plants to install NO_x controls equivalent to the state-of-the-art in Europe -- at the moment, Selective Catalytic Reduction ("SCR").

No bills have yet been introduced in the House, but Representatives Waxman and Sikorski are said to be readying one. Judging by previous bills they have introduced, it will also require NO_x controls on large sources.

A number of factors favor passage of legislation in this Congress.

First, there is the widespread support for acid rain control in Congress, which echoes strong public support.

In the last Congress more than 170 members of the House of Representatives -- about 1/3 -- cosponsored the Waxman-Sikorski bill.

In the Senate, the last election probably resulted in a swing toward a bill of as much as 16 votes, probably assuring a substantial majority for controls.

The major opponents of an acid rain law have been two powerful Congressional Democrats and one Republican President. With Presidential politics increasingly in the air, members of Congress may become less willing to accept their veto over an important environmental priority.

Finally, there is a strong feeling that Congress must amend the Clean Air Act this year to avoid the imposition of sanctions on most major metropolitan areas for their failure to meet the law's health standards.

Many believe that this bill will provide an occasion for including acid rain controls in the Act.

I said at the outset that a new and positive environmental agenda is forming. The progress of acid rain legislation will be a good indicator of whether this new agenda can be addressed by this Administration, or must wait for the next.

Either way, we can expect that the '90's will be a period when nitrogen oxides from stationary sources will be controlled in the interest of public health, esthetics, and environmental integrity.

Technology to accomplish substantial control in many applications already exists. But the perfection of these techniques and the commercialization of others may offer greater environmental benefits in the future.

For these reasons, I commend the sponsors of this symposium and hope this week will be a very productive one.

DECLINE OF BOREAL MONTANE FOREST ECOSYSTEMS IN CENTRAL EUROPE AND THE EASTERN NORTH AMERICA - LINKS TO AIR POLLUTION AND THE DEPOSITION OF NITROGEN COMPOUNDS

by: Dr. Robert I. Bruck
Associate Professor of Plant Pathology and Forestry
North Carolina State University
Raleigh, NC 27695-7616

ABSTRACT

Recently presented evidence of anamolous growth declines and dieback of eastern forests has captured public concern and strengthened the call to resolve the longstanding question of the role of atmospheric deposition in the decline of forest trees. The objective of this paper is to summarize recent evidence relevant to determining if there are effects of atmospheric deposition on forests of the eastern United States. A scenario might involve various forms of concentrated pollution being deposited via cloud deposition, causing above and below ground nutrient and microbial imbalances or direct physiological aberrations to spruce and fir trees. These chronic perturbations could lead to a predisposition of the ecosystem, to the effects of many indigenous pathogens and insects, and/or weaken the trees resistance to the effects of severe climate. Continued research to integrate the findings of long term studies with relevent atmospheric monitoring data will create a clearer picture of the potential of atmospheric pollution to affect American forest resources.

The work described in this paper was not funded by the U.S. Environmental Protection Agency and therefore the contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

INTRODUCTION

Recently presented evidence of anamolous growth declines and dieback of eastern forests has captured public concern and strengthened the call to resolve the longstanding question of the role of atmospheric deposition in the decline of forest trees. The objective of this paper is to summarize recent evidence relevant to determining if there are effects of atmospheric deposition on forests of the eastern United States. The current understanding of acidic deposition effects on forests is of modest depth, stemming largely from theoretical studies or experimental studies where there is limited information available on the effects of acidic deposition. At present, there are no field studies in the U.S. in which any of the potential effects have been convincingly established as interfering with forest productivity. However, many proposed effects will be extremely difficult to detect because of the complex and dynamic nature of forest ecosystems and/or the length of time it would take for the effects to be clearly manifested. In this paper, data suggesting a nominal increase in subalpine spruce fir forests of the eastern U.S. are presented. Then hypotheses which might link atmospheric deposition to the observed phenomena are reviewed in light of available data with emphasis on the possible effects of acid deposition and particularly nitrogen compounds.

Much attention has been paid to and a number of surveys in one or more aspects of forest decline are underway or recently completed. These vary in scope and scale and include measurements of population changes over time, trends in annual growth, trends in wood density and chemistry, and trends in response to climate as measured by stand health and vigor. The major objective of most of these surveys is to document the existence of adverse trends in the forests which are suspected based on preliminary observations. Thus, those surveys should be regarded as case studies and not necessarily representative of all forest conditions. It is important to note that few studies from the U.S. have been designed to test hypotheses regarding cause and effects of atmospheric deposition. Recent observations in northern and southern Appalachian boreal montane ecosystems suggest that the pattern of foliar loss or dieback and decline is a phenomenon which is often most obvious at either the outside of the branches and the top of the tree or from the inside of the branches working distally out to the ends of the trees. Trees of any size, class, shape can exhibit symptoms. In early stages of dieback the branches may have several years needles, whereas in later stages only a few terminal of needles will be retained. In both northern and southern forests complete defoliation and death apparently only takes a few to several years to be attained. No quantitative evidence as to the exact rate of disease progresss is at hand at the present time. Several recent publications report obvious and recent alterations in diameter growth rates in several non-urbanized parts of the eastern U.S. including boreal montane ecosystems. More subtle anomalies in growth which have persisted for the two or three decades have also been reported from widespread tree core analyses. Much attention has been given to the possibility that airborne pollutants have been responsible for some of the recent growth changes. Identification of the existence of abnormal growth trends is difficult for several reasons. Long term data on natural variations in ecosystem structure and function which could influence growth, is lacking. Influences of bygone natural and human disturbances are often ignored or are difficult or impossible to determine. Another key problem is that trends in the tree ring record collected at any point in time represents a biased account of forest dynamics because, obviously, only survivors are present, and past records of lethal stress are not necessarily fairly represented. It is therefore difficult to interpret the meaning of recent trends in declining growth, however, an increasing body of knowledge is being accumulated correlating the incidence of forest decline with anthropogenic pollution.

HISTORICAL PERSPECTIVES ON FOREST DECLINE

Air pollution damage to forests is not new. As the Industrial Revolution gathered momentum in the latter part of the 19th Century, many point sources of pollution were responsible for high levels of atmospheric contaminants. Trees and other vegetation have been dying near metal smelters, chemical plants, refineries, and fossil fuel-fired power stations for the past one hundred years or more. Forests in Central and Eastern Europe have been suffering periodically from "smoke damage" since the middle of the 19th Century. The "smoke" usually consists of sulfur dioxide, nitrogen oxides, and heavy processes, metal smelters, and power plants. However, such damage was usually found close to heavily industrialized, urban areas; it was seldom generalized over entire regions.

In recent years the pattern of pollution in Eastern Europe has changed dramatically. Czechoslovakia, in particular, has become very heavily polluted. Total gaseous emissions jumped from 3.6 million metric tons in 1960 to 7.3 million metric tons by 1980, an increase of more than 100 percent. The amount of sulfur dioxide generated in 1980 was 3.2 million metric tons, while 1.6 million metric tons of nitrogen oxides were also produced along with 500,000 metric tons of hydrocarbons. As a result of these various facts, Czechoslovakia is now among one of the most intensely air polluted countries in the world. On average, about eight metric tons of atmospheric pollutants per inhabitant are generated annually. The same is true for the world. On average, about eight metric tons of atmospheric pollutants per inhabitant are generated annually. The same is true for the heavily industrialized parts of Poland and East Germany, which are known to have large areas of "smoke" damaged forests. In an effort to combat the damage, Poland has been experimenting with pollution-resistant trees for the past 15-20 years.

Gaseous pollutants, like sulfur dioxide, hydrogen fluoride, and ozone, have played prominent roles in past declines, but their destructive effects have been relatively "localized", or limited to specific areas under continuous assault from airborne pollution. As early as 1910-11 damaged trees (mostly lodgepole pine and Douglas fir) were investigated in the Deerlodge National Forest located near the Washoe metal smelter at Anaconda, Montana. They were found to be suffering, in part, from sulfur dioxide pollution, which retarded their growth. Similarly, ozone has damaged or killed thousands of ponderosa and Jeffrey pines in the San Bernardiono Mountains east of Los Angeles, California, a city famous for its yellow-brown photochemical smog. A U.S. Forest Service survey carried out in 1969 revealed that some 1.3 million ponderosa pine growing on 405 square kilometers in the San Bernardino National Forest were stressed and dying. In areas with the highest ozone concentrations, timber yield was found to be reduced by 80 percent or more. Today, both ponderosa and Jeffery pines have been seriously damaged of killed over wide areas in the San Bernardino Mountains, resulting in a markedly altered forest ecosystem.

However, natural stresses like drought, frost, and winter damage along with biotic factors such as insect infestations, fungi, and other disease organisms have probably figured prominently in most large-scale forest declines of the past. Between 1871 and 1880, for example, red spruce forests from New York State to New Brunswick, Canada were devastated by what has since been attributed to a combination of drought conditions and insect attacks.

Historically, most forest damage was limited to one or two agents, or a combination of several; in nearly every case there were visible "smoking guns". Moreover, the damage was usually localized or, if regional, involved only a few species. Never before has such large-scale and rapidly spreading forest decline been observed affecting so many different species under such varied ecological conditions. Over the past 50 years there have been 19 major or minor regional forest declines in Europe and North America. Of these 19 reported declines, at least seven implicate air pollutants as a primary, or at least a contributory, cause. With one exception, all of the pollution-related declines developed (or at least were noticed) within the last eight years. Increasingly, the finger is being pointed at airborne chemical pollutino as the major cause of forest decline and death, however no proof has been offered.

DAMAGE TO FORESTS

Waldsterben in Central Europe is, by far, the most complicated and serious forest decline on record. Dr. Peter Schutt, Professor of Forest Botany and Pathology at the University of Munich and Dr. Ellis, Cowling, Associate Dean for Research at the School of Forest Resources at North Carolina State University in Raleigh, have produced a comprehensive description of Waldsterben. The following features of the "disease" and its extent are noteworthy:

1. Visible symptoms of Waldsterben began around 1979-80 in many different parts of Europe and within four years the "disease" had spread over large areas of the continent.

2. As of late 1985, Waldsterben was still increasing in intensity and geographic distribution and is associated with an alarming frequency of damage from secondary stress factors such as insects, needle and root fungi, and climatic stresses (i.e., frost, wind, and snow damage).

POLLUTION-RELATED FOREST DECLINE

Widely assumed major role:

- Waldsterben in Europe
- Decline of ponderosa and Jeffrey pines in the San Bernardino Mountains, California
- Regional decline of white pine in the eastern United States and Canada

Possible major role:

- Decline of red spruce, and balsam, and Fraser firs in high elevations in the Appalachian Mountains from Georgia to New England
- Growth decline without other visible symptoms in loblolly, shortleaf, and slash pines in the Piedmont regions of Alabama, Georgia, North and South Carolina
- Growth decline without other visible symptoms in pitch and shortleaf pine in the Pine Barrens region of New Jersey
- Widespread dieback of sugar maples in northeastern United States and southeastern Canada

Declines related to biological or physical factors

- Tannensterben (white fir decline) in Europe
- Kiefersterben (Scotch pine decline) in East Germany and European Russia during early 1970s

- Oak decline in Germany and especially in France since early 1900s
- Decline of *Pinus pinaster* on the Atlantic coast of France since early 1980s
- Beech bark disease of northeastern United States and southeastern Canada
- Littleleaf disease of shortleaf pine in the southeastern United States
- Birch dieback in the northeastern United States and southeastern Canada
- Poleblight of western white pine in the Rocky Mountains
- Maple decline in the northeastern United States and southeastern Canada
- Oak decline in Pennsylvania, Virginia, and Texas
- Ash dieback in the northeastern United States and southeastern Canada
- Sweetgum blight in the southeastern United States

---

3. Within five years it affected nearly every tree species in central Europe including the four most commercially important conifers (spruce, fir, pine, and larch) and six angiosperms (beech, birch, oak, ash, maple, and alder).

4. Various species of shrubs and herbs have been damaged in certain affected forests.

5. The symptoms are heterogeneous from one region to another, from one stand to another, and even within the sampe species in the same stand.

6. Waldsterben occurs with similar intensity on poor and rich soils, acid and basic soils, and on wet and dry soils, independent of their geological origin.

7. The symptoms often are more severe in high elevations, but they occur in middle and low elevation sites as well.

8. Different forest management practices and the compositon of the forest (i.e., single versus mixed stands, planted vs. natural) do not appear to have a significant impact on the amount of damage.

9. Young trees are normally note as severely affected as older ones, but even this varies from region to region.

10. Some of the typical symptoms have never been described before (especially for beech, spruce, and larch).

11. The worst damage appears in higher elevation forests on slopes facing the prevailing winds.

12. Most of the victims show both growing-decreasing and abnormal growth

symptoms.

The Waldsterben phenomenon is characterized by three broad indicators of destruction: growth-decrease, abnormal growth, and water stress.

Cowling cautions that although the comon symptoms of Waldsterben include increased susceptibility to biotic and abiotic stress factors, this dieback pattern is very different from the normal disease induced by familiar biotic forest pathogens-fungi, bacteria, nematodes, insects, and viruses. It is also distinct, from the typical injuries to forests induced by drought and frost, or by gaseous air pollutants like ozone and sulfur dioxide.

Symptoms in Spruce in the Northern Montane Forests

Observations in the northern Appalachians suggest that the pattern of foliar loss (dieback) is a phenomenon which is often most obvious at the outside of the branches and the top needles are damaged (brown tips or bands, completely brown, or missing). Trees in any size class can show the symptoms. In early stages of dieback, the branches may have several year's needles (>6 yr), whereas in the later stages, only a few years needles are present. Those needles are either old needles or can be new needles on the few remaining live branches. The remaining foliage is often in the middle portion of the crown with the ends of the branches defoliated. In the northern forests, complete defoliation and death apparently take a few to several years, but no quantitative evidence of the rate of disease progression is in hand. Additional details of the foliar loss patterns are presented in a later section, as they apply to one specific hypothesis.

An additional foliar symptom in northern Appalachian red spruce is apparent as occasional small (<0.5 mm) necrotic spots on the older foliage. Pronounced chlorosis or yellowing of the needles is very rare, although a slight yellowing is often present.

Preliminary data on spruce foliage revealed marginal P and Mg deficiencies. At lower and middle elevations, spruce are infected by root rot fungi which are secondary in nature. Armillaria mellea is the most prominent, but is not universally present. Research on the role of secondary pathogens is progressing, and promises to produce clear evidence that a set of organisms infecting the weakened hosts are participants in the decline syndrome. To date, no studies have shown the presence of a biotic pathogen which can act as a primary agent.

Southern Appalachian Survey Results

During the 1984 field season, permanent plots were established on six of eight mountain areas visited. The northernmost area studied was Mt. Rogers in Virginia. Moving southward, plots were established on Grandfather Mountain, Roan Mountain, Mt. Mitchell, Clingman's Dome (GSMNP), and Mount Le Conte (GSMNP). The southernmost site visited was the Joyce Kilmer Wilderness area, however, permanent plots were not established at this site due to a lack of suitable stands of red spruce and Fraser fir. This was also true of the Plott Balsams which are located east of the Great Smoky Mountains National Park.

A decline class rating of 1 signifies relatively healthy trees with a defoliation index of between 0 and 10%. As shown in Figs. 1-12, the average number of trees below 5,600 ft throughout the southern Appalachians in 1984 showing a decline class rating of 1 is approximately 79%. However, the west-facing slope of the respective mountainsides have a significantly greater amount of decline symptomatology with only 62% of the trees in decline class 1. Figure

2 illustrates the frequency of decline for all high elevation sites sampled. The average percent of the high elevation trees showing decline class 1, i.e., healthy trees, is generally, less, with an average of 68% in this category. Only 54% of trees on west-facing slopes fell into decline class 1, thus indicating that approximately one-half of all high altitude trees exhibited some decline symptomatology. Similar trends were observed for Fraser fir.

Increment cores were removed from only dominant and co-dominant red spruce and Fraser fir trees. Figures 13-19 outline the results of this increment core analysis for Mt. Rogers and both high and low elevation sites on Mt. Mitchell. On these mountains there and on Roan Mountain and Grandfather Mountain was an abrupt and synchronous suppression of annual growth of both Fraser fir and red spruce beginning in a window period of approximately 1958-1965.

However, we consistently found that red spruce was in a much more serious state of growth suppression than was Fraser fir at all sites. Perhaps the most abrupt increment suppression observed was on Mt. Rogers in Virginia. Although the amount of visible decline here was the least of the sampled sites in 1984, increment suppression was found in all the spruce sampled, with approximately a five-fold decrease in radial increment since 1960 as compared to the annual increments from 1950 to 1960.

The overall frequency of red spruce increment suppression averaged approximately 82%. The lowest incidence of approximately 43% was found in the low elevation red spruce trees on Mt. Mitchell. The definition of severe increment suppression used in this study is at least a 2-1/2 fold decline in the average annual increments of 1960-1970 as compared to 1950-1960. Virtually all red spruce trees showed some slowing of growth during this period; however, many natural factors such as the natural aging process can account for a relatively slower growth rate.

During the months of April-June 1985 and 1986 a resurvey of all 1984 permanent plots was undertaken using the same decline ratings scale employed in 1984. The percentage of trees exhibiting decline symptomatology in 1985 is significantly higher than that observed in 1984. The most significant shift in observed classes was in red spruce where 88% of the trees was scored as class 1 (healthy) in 1984 and only 49% of these trees remained in this class in 1985. In addition it was observed that all "decline" rating classes had significant increases for both red spruce and Fraser fir in 1985. In 1986 additional shifts from "healthy" to decline classes were observed. Although these shifts were not nearly as dramatic as those observed in 1985; the trend, nevertheless, continues toward deterioration of stand condition.

Needle samples collected from Fraser fir and red spruce trees in 1984 were analyzed for 28 macro- and micronutrients and trace elements (N, P, S, Ca, Mg, K, Cu, Fe, Mn, Zn, Co, Al, Ba, Br, Ce, Cl, Cr, Cs, Hg, La, Na, Ni, Pb, Rb, Sb, Sc, Sm and Th) (Figs. 21-22). Comparison of the results of these analyses with previously reported elemental analyses of Fraser fir and red spruce indicated no significant nutrient deficiencies occurring in the dominant and codominant trees sampled, except for calcium. The mean concentration of calcium observed in red spruce needles (1440 mg/kg, n=30, 1984 growing season) fell below that reported for red spruce foliage in the northeastern United States (1830-7900 mg/kg). Calculated Ca:Mg ratios (1.44 - 2.97, 1984 growing season) were also lower than those calculated from published results for red spruce foliage in the Northeast (3.00 - 5.62), suggesting that the concentration of calcium in red spruce needles in the southern Appalachian Mountains may be approaching values thought to be deficient for good growth. The concentration of calcium in Fraser fir foliage (3350 mg/kg n=41, 1984 growing season) was also lower than reported values (1200-7700 mg/kg), but not to the extent demonstrated for red spruce trees.

One anomally observed in the foliar nutrient data was a lack of a decrease in nitrogen concentration with increasing age of red spruce needles (1.05, 1.13, 1.07% for 1984, 1983, 1982 flush years, respectively). Such a decrease would be expected for a mobile element like nitrogen, and is observed for phosphorus, magnesium and potassium. The lack of a decrease in nitrogen concentration with increasing needle age suggests an increase in the availability of nitrogen, either in the soil or via foliar uptake of atmospheric nitrogen.

Analysis for the foliar concentration of such elements as mercury, arsenic and selenium yielded results at or below the detection limits for the techniques employed (0.010, 0.050, and 0.1 mg/kg, respectively). Lead was found to be present in the analyses of both red spruce and Fraser fir needles, with Fraser fir generally having higher concentrations, particularly in the older needles (0.65, 2.86, and 2.78 mg/kg, N=41, for 1984, 1983, and 1982 flush years, respectively). Comparison of lead concentrations with those of other rare-earth elements known to be associated with dust on needle surfaces (cerium, lanthanum, scandium, samarium and thorium) suggests that a substantial portion of the lead found was due to particulates on the needle surfaces and not to uptake and translocation from the roots into the needle tissue. The higher concentrations of lead associated with Fraser fir versus red spruce needles may be due to differences in needle morphology and chemical composition of the waxy cuticle.

Substantial amounts of lead were found in the forest floor of the spruce-fir forests of the southern Appalachian Mountains. However, lead is also present in the underlying mineral soil because of the lead content of the original rock from which the mineral soil was derived. Lack of a clear separation between the forest floor and underlying mineral soil leads to an overestimation of the amount of lead deposited by atmospheric processes by simply summing the mass of lead found in the top 12 cm of soil. Cesium-137 and lead-210 were used to provide an estimate of the extent of incorporation of Pb from anthropogenic sources into the soil profile. A correction factor was then applied for the lead extracted from the mineral matrix of the surface soil samples. This approach yields estimates of total lead deposition of between 600-1300 mg/m^2 for the spruce-fir forests in the Southern Appalachian Mountains. This estimate is only 40-50% of that reported for similar ecosystems in the northeastern United States (1800-2000 mg/m^2). However, further work is needed to generate the necessary database in order to determine whether the deposition of lead in the mountains of the southern United States is in fact less than that in the northeast.

Resurvey of the Cooper/Adams Plots on Mt. Mitchell, NC.

During the summer of 1959, Dr. Arthur Cooper and Dr. Dave Adams (NCSU) established a large (25 acre) quadrat for the purpose of evaluating the community structure on the east face of Mt. Mitchell, N.C. (6,684'). The quadrat was established at a high-point of 6,570' and traversed an area NNE to an elevation of 5,930'. A series of 9 smaller quadrats were placed within the larger for the assessment of overstory trees, saplings and understory herbaceous cover (Fig. 20).

Beginning in August 1985 and continuing through August 1986 a re-survey of the plots established by Drs. Cooper and Adams was conducted. A total of 5 of the 9 original plots were successfully re-established. The following is a summary of our findings.

- The upper canopy is composed of significantly fewere live stems at the present time. Live basal area is also significantly reduced. The influence of the balsam wooly adelgid on fir cannot be overemphasized at this altitude where fir predominates; however live red spruce in both the overstory/shrub and understory herb/seedling strate are also significantly reduced (Tables 3-5).

- Spruce/fir reproduction has been significantly altered. At present there are far more stems/acre, however this is characterized almost exclusively by fir seedlings and saplings, red spruce regeneration is rare to absent. Young fir of 1 m or more in height seem in a good state of health, and appear not to be significantly effected by the adelgid, however competion is great, and significant mortality of young trees, has been noted.
- The incidence and frequency of herb species has been greatly changed, where there are many fewer species in the now "open" ecosystem with a few (Carex, Rubus) becoming very dominant. Species richness has been greatly reduced.

DISCUSSION

Anamalous Diameter Growth

Several recent publications report obvious and recent alterations in diameter growth rates in several non-urbanized parts of the eastern U.S. (1) (2) (3) (4). More subtle anomalies in growth which have persisted for the past two or three decades have also been reported from tree core analyses. These include changes in the response to climate (3), reduced latewood density (2), and alterations in the patterns of elemental accumulation in bole wood tissues (7).

Much attention has been given to the possibility that airborne pollutants have been responsible for some of the recent growth changes (2) (1) (7). Identification of the existence of "abnormal" growth trends is difficult for several reasons. Long term data on natural variations in ecosystem structure and function, which could influence growth, are lacking. Influences of bygone natural and human disturbances are often ignored or difficult to determine. Another key problem is that trends in the tree ring record collected at any point in time represent a biased account of forest dynamics because only survivors are present, and past episodes of lethal stress are not necessarily represented. It is therefore difficult to interpret the meaning of recent trends in declining growth. In light of those cautions we summarize below some recent tree ring data which are relevant.

Figure 6 represents expected growth rate patterns in the absence of major stand disturbances or change in climate for red spruce, the species in which we believe anomalous growth is clearest. Early growth rates are generally low when the trees are suppressed beneath the canopy, increase when the trees attain canopy height, and level off at a rather constant or gradually decreasing growth rate. Superimposed on these aging trends are year-to-year variations caused by small disturbances, and other factors, such as year-to-year variations in temperature and soil moisture. Figure 7 shows the effect of large-scale disturbances which can obviously have overriding effects on trends in average raw ring width values. At Hubbard Brook, a hurricane in 1938 blew down an estimated 40% of the stand (C. Cogbill, personal communication), accounting for the release effect. Subsequent closure of the canopy and natural competition accounts for all or most of the return to the average annual growth rate observed prior to 1937.

In Figures 8-10, tree ring chronologies from Mt. Washington, Mt. Mansfield, and Whiteface Mt., NY are shown for three representative elevations. These data suggest a synchronized change in radial growth characteristics after about 1960.

At some sites in the southern Appalachians sampled by Johnson and Siccama (1983), the same anomaly in radial growth is observed (Fig. 11).

Raw ring width values from most of the 1984 survey sites in the southern Appalachians also suggest a marked change sometime around 1960 (Fig. 12-14). The cause, or causes, of the growth changes are at present obscure. There is no obvious, natural cause, and as much as anything else the widespread nature and timing of the change in growth have led to the research and speculation that airborne pollutants may play a role in altering growth rates of high-elevation red spruce.

Forest Damage in the Federal Republic of Germany

Forest damage in the FRG is easily visible in many forest areas and is the focus of a vigorous research effort. The German scientific community is advanced compared to the North American scientific community with respect to identifying damage, characterizing the symptoms at ecosystem, plant and cell levels, and developing specific hypotheses to identify the mechanisms involved. There is a general consensus that airborne pollutants are the primary cause of the symptoms observed (8) with numerous natural factors (drought, needle cast fungi, site characteristics) implicated as secondary factors. The pollutants involved and the mechanisms and combinations of stresses which are thought to be important are being researched, but have not been clearly established and accepted by the scientific community.

Hypothesized Causes

The hypothesized mechanisms leading to the damage are varied, having been based on observations of different symptoms, and different experimental approaches. One prominent line of investigation involves below-ground effects triggered by acid deposition which alters the soil environment resulting in soil acidification, release of Al, Mn, and heavy metals, shifts in elemental balances, and further alteration of natural acid generating and consuming processes (9). It is suggested that these changes are linked to tree damage by adverse effects of soil acidification on roots, specifically, Al toxicity which interfers with Ca and Mg uptake and normal root develoment. Several studies suggest that those mechanisms are plausible, for the highly acid mineral soils studied by Ulrich and co-workers, including studies of annual root dynamics, hydroponic experiments, and elemental analyses of roots cells (11).

Another prominent view (which does not exclude below ground effects) is that the important effects occur above ground. The following excerpt reflects the view of the Federal Ministry for Research and technology of the above-ground damage scenario (March 1984 Report).

"Findings taken from field studies and supported by experiments under defined conditions in controlled climate chambers enable us to conclude that high sulfur dioxide concentrations contribute to the damage to forests now being observed; i.e. by damaging cell membranes, inhibiting the process of photosynthesis, disturbing the regulatory function of the stomata and, consequently, disturbing the internal water regime. Analysis of needles taken from damaged spruce show strong magnesium and zinc deficiencies as well as low calcium content. It can be assumed from this that increased magnesium loss contributes to the formation of damage. When there is interference in their water regime, plants react by changing their hormone spectrum, as has been known for years on the basis of physiological studies carried out on crop plants. By forming a hormone (abscissic acid), plants attempt to exert influence on the regulation of the stomata. The formation of ozone and other photochemical oxidants is connected with general air pollution in that it results from the emission and transformation of nitrogen oxides and hydrocarbons. Increasing importance is being attached to the influence of photochemical oxidants in triggering damage to forests, since there has been a marked increase in the emission burden caused by this group of substances in recent years. In addition, due to the specific conditions of their formation and elimination, photochemical oxidants represent a group of noxious substances that can be expected to occur in greater concentrations at a distance from the soruce than in the source vicinity and which, on a daily average, occur in higher concentrations in the nocturnal inversion layer than at valley levels. The possibility cannot be ruled out that natural pathogenic factors (fungi, pests) as well as climatic and locational influences also play a role in the occurrence and characteristics of the damage registered.

The impact of individual influences varies in accordance with the different conditions present at each location so that under certain conditions each influence may play a more or less crucial role in triggering and in determining the extent of damage. However, the evidence available to us now would seem to indicate that these influences can be largely ruled out at triggering factors."

To break this down a bit more, the German scientific community has four main schools of thought. Three of these recognize a primary stress which is coupled with ancillary site factors. These are the aluminum toxicity, ozone and SO_2 "hypotheses." The fourth idea is more general, suggesting that combined effects of pollution stress alter hormonal balances in the trees, resulting in the visible symptoms.

Although the Ministry has adopted a strong favor for the above ground scenario, the clear scientific evidence is not in hand, and more research is needed to confirm any of the scenarios.

Research Related to the Cause of Red Spruce Decline

In discussing hypotheses, it is important to point out that for red spruce, there is very little published information at the plant (i.e. physiological, nutritional data, visible symptoms) or cell level (i.e. histological characteristics). There are some available data at the ecosystem level (stand dynamics, site characteristics), but it is far from thorough. All in all, there are few data on which to base specific, testable hypotheses. Thus, at present the hypotheses offered are of a general nature, and there are several owing to the lack of basic information. A very thorough description of ecosystem, plant, and cell level phenomena will be paramount for the construction of detailed, specific, testable hypotheses regarding the causes and mechanisms involved. If the North American scientific community is to take advantage of German experience, a comprehensive set of observations needs to be generated, and compared to the German experience.

Sulfur Dioxide

Classic symptoms of acute SO_2 damage are lacking in the German forests, but there is suspicion that the levels observed in Germany may provide important stress contributing to cell membrane damage and altering basic physiologic processes (Rehfuess, 1983). The ambient levels of SO_2 in the forested areas of Germany in which dieback has been observed have been summarized by Tomlinson (1983) and the average annual values range from approximately 7 to 21 ug m^{-3}. The information available in the U.S. does not suggest a major role for gaseous SO_2 damage. At Hubbard Brook, NH, the annual average SO_2 concentration was determined to be 2.5 ug m^{-3}, or approximately an order of magnitude less than levels thought to cause observable foliar symptoms through chronic exposure. There are currently no data from declining red spruce which indicate alterations in structure or function caused by SO_2, but the possibility has not been carefully investigated.

Ozone

Considerable research in Germany has been oriented toward identifying whether or not ozone, alone or in combination with other factors, is an important causative agent in "Waldsterben" (forest decline). A case of circumstantial evidence has accrued suggesting a role for ozone, possibly in combination with leaching accelerated by acidic fog or cloud moisture. In the U.S. case, little or no attention has been given to ozone as a participant in red spruce decline.

The following summary is based on publications from the Landesanstalt fur Immissionsschutz des Landes Nordrhein Westfalen, Essen, FRG (12), and refers to the observations and experiments of Bernhard Prinz and coworkers, who have carried out experimental studies and field studies in North-Rhine Westphalia.

Damage to Norway spruce and silver fir in southern and eastern Germany is most prominent at high elevations (>800 m), and on windward slopes, albeit there are some regional differences. Damage occurs on acidic soils as well as on high base status calcareous, soils. Individuals in all age classes are affected. The visible, above ground symptoms of the damage are as summarized earlier. In the most common cases, the loss of foliage begins at the base of the crown and at the inside of the branches, progressing upward and outward. The oldest needles on the oldest branches are shed first. The needles, particularly the older needles, turn chlorotic (yellow-green) in a speckled manner. Ultimately, the needles turn strongly yellow, and show pronounced Mg deficiency and low Ca content.

The needles are shed quickly by fir, but remain on spruce for some time. In spruce, the upper surfaces of the needles are more chlorotic than the lower surfaces. Additionally shaded branches are less affected than unshaded branches, suggesting some role for sunlight. This is consistent with the observations that the trees which are at the edge of a stand, and those which emerge above the general canopy, show the most damage. It should be noted that there are exceptions to this pattern.

A variety of studies was conducted (12) which sought to characterize the potential for injury from acidic fog, airborne substances such as SO_2 and NO_x, ozone, biotic agents (such as viruses) and vehicle exhaust. Additionally, details of airflow patterns and ozone monitoring at several altitudes and locations provided empirical evidence of ambient ozone concentrations. Ambient ozone concentrations of 150 $\mu g\ m^{-3}$ were exceeded quite frequently and concentrations of 240 $ug\ m^{-3}$ were exceeded occasionally. In controlled experiments, ozone fumigations for 6-8 weeks, 24 hr day^{-1} using 150 to 1,200 $ug\ m^{-3}$ caused yellowing and mottling similar to that observed in the field, however all of the symptoms observed in the field could not be reproduced. Acidic fog treatment (pH 3.5 and 4.5) for two months (5 hr day^{-1}, 5 days wk^{-1} caused no visible injury to spruce or fir. Combinations of ozone and acidic fog treatments indicated that the combination enhanced the loss of Mg from the foliage. Analyses of concentrations and exposure time (accumulated dose) calculated from field data were consistent with accumulated doses which caused yellowing in controlled experiments.

In assessing whether or not ozone is involved in the decline of red spruce, it is important to point out that the symptoms in the northern Appalachians appear to be substantially different whereas the symptoms in the southern Appalachians appear to be more similar to those described above for German conifers. We point out, however, that careful, systematic comparisons of symptoms have not been completed at this time.

Ozone levels in the high elevations of the northeastern U.S. have not been systematically researched, except at Whiteface Mountain, NY. Typical summer levels at Whiteface are in the 80-110 ug m^{-3} range (Burgess et al., 1984; J. Kadlecek, ASRC, SUNY, Albany, NY, personal communication) which is slightly higher than levels measured at clean air areas (60-90 ug m^{-3}) and about half of the values cited in the German work discussed above. Peak values at Whiteface Mountain currently research about 160 ug m^{-3} (J. Kadlecek, personal communication). At present we must regard the possibility of ozone damage in the U.S. as speculative--without supporting information, but without contradictory information.

Acidic Deposition

The role of acidic deposition in the German and U.S. forest decline is currently the focus of much research, debate and speculation. As indicated earlier, there are many potential effects of acidic deposition on forests. In this section we review those possibilities which ahve been suggested by recent forest research as possible effects which are being realized at the present. Several hypotheses have emerged from U.S. and German research efforts: 1) Al mobilization in the soil leading to toxicity, and/or physiological drought, 2) cation depletion of the soil, 3) NO_3 deposition resulting in suppression of mycorrhizal development, 4) excess N uptake resulting in decreased frost resistance.

Effect of N on Frost Hardiness in Conifers

Another adverse effect that nitrogen fertilization may have on forest trees is in reducing frost hardiness. Our observations of apparent frost damage to the previous year s needles of red spruce over the past 5 years strongly suggest that repeated winter damage to foliage is a component of the spruce decline syndrome in the northern Appalachians (13). There are three plausible factors which alone, or in combination, could predispose red spruce to winter damage: 1) natural susceptibility to frost damage, 2) decline in vigor caused by stresses of the decline syndrome, 3) lack of frost hardiness induced by nitrogen.

In regard to the first possibility, winter injury due to a lack of hardening or due to excessive cuticular transpiration has been suggested as a natural stress which limits the geographic and elevational ranges of conifers and red spruce may be naturally susceptible to winter injury. The latter authors reported winter injury to a number of conifers in the Adirondacks of New York and damage to red spruce was greater than to any of the other conifers present. With respect ot the second possibility, red spruce have been declining in vigor for two decades (3) and it is plausible that the highly stressed trees are unable to fully harden and/or produce an adequate cuticle as a result of the stress syndrome.

With respect to the third possibility, it is suggested that there is sufficient evidence to formulate a testable hypothesis regarding the role of nitrogen in promoting a predisposition to winter damage. First, foliar nitrogen concentrations, mortality, and dieback symptoms in reproductive-size red spruce all increase with elevation (3). Second, nitrogen deposition is much greeater at high elevation sites than at low elevation sites in New England. High elevation N deposition estimates cited previously (16), are about six times the wet N deposition measured at low elevation at Hubbard Brook (i.e. 6.5 kg N ha^{-1} yr^{-1}). The high elevation deposition rates could be significant considering that: 1) fertilization rates of 100 to 200 kg N ha^{-1} yr^{-1} (applied at 500 to 1,000 kg N ha^{-1} at 5 yr intervals) were sufficient to promote frost damage to Norway spruce (Picea abies Karst) and Scots pine (Pinus sylvestris L.) in Finland and 2) a total of 495 kg N ha^{-1} applied in six equal quantities over a 10-year period caused mortality in jack pine (Pinus banksiana Lamb.) in Quebec. Additionally, abnormalities in mesophyll cells of red spruce foliage at Camels Hump, VT are similar to abnormalities observed in frost-damaged, N-fertilized conifers in northern Finland (13).

It is conceivable that nitrogen supplied to foliage by cloud water and/or to the soil by clouds and precipitation induces growth later into autumn and delays differentiation of cuticularized epidermis. If cuticle thickening is not optimum, and if starch to sugar conversions are not completed the plants are more susceptible to damage from winter desiccation or early frost. The possibility of repeated frost damage induced by nitrogen must be considered speculative, but cannot be rejected with any current data, and as such, should be tested.

Indirect N-Effects

According to van Breeman et al (17) the net proton production related to the nitrogen transfers can be formulated as:

$$(NH_4^+in - NH_4^+out) + (NO_3^-out - NO_3^-in);$$

The uptake of HN_4^+ by the vegetation generates on e mole of H^+ per mole of NH_4^+. Conversely, NO_3^- uptake generates on emole of OH^- (or HCO_3^-) per mole of NO_3^-. These proton flows occur in the opposite direction during the mineralization and nitrification: one mole of OH^- is generated per mole of organically bound nitrogen which is converted to NH_4^+, while nitrification generates on e mole of H^+ per mole of organic nitrogen, (equivalent to two moles of H^+ per mole of NH_4^+ which is converted to NO_3^-).

If the expression above is > 0, the nitrogen flows will cause a net proton production within the ecosystems.

According to the bulk deposition data from 1983 (Table 1) the balance between ammonium and nitrate would generate 5 (3) mmole H^+ m^{-2} yr^{-1} in southern Sweden (south of 60° N) and 2(2) mmole H^+ m^{-2} yr^{-1} in northern Sweden. the figures are arithmetical averages with standard deviations within brackers. They correspond to approximately 16% and 13% respectively of the direct bulk depositoin of H^+ during the same year. These latter deposition figures are 31 mmole m^{-2} yr^{-1} and 15 mmole m^{-2} yr^{-1}. The proton generation related to the nitrogen input thus seems to rather low. This might also be the case even if the dry deposition is considered. According to a deposition study performed by Grennfelt et al (1985), which included both wet and dry deposition, the proton production resulting from the nitrogen deposition viewed in isolation, could be anything between -22 mmole m^{-2} yr^{-1} (i.e. a surplus of NO_3^-) to 23 mmole m^{-2} yr^{-1} (i.e. a surplus of NH_4^+). The extremely wide range is a good illustration of the difficulties involved in estimating the dry nitrogen deposition.

Another important aspect of the nitrogen deposition should be mentioned however, namely that a correlation analysis based on the 1983 bulk deposition data showed a fairly close relationship between the H^+ concentration and the nitrate concentration while the corresponding correlation with sulphate was much weaker (cf. Benarie & Munn 1980). The R2 values for the pH/NO_3^- correlation varied between 0.28 and 0.88, the average for all stations being 0.62. The regression coefficients (the NO_3^- concentration expressed as mgN/liter), varied between -0.47 and -5.20 and the intercepts between -0.47 and -5.20, and the intercepts between 4.61 and 5.36. These correlations indicate that an increasing share of nitrate in the deposition as compared to sulphate would cause a further pH decline. If the calcium and magnesium concentrations remain constant, there would be a decline of the lime potential.

As to nitrification and nitrate leaching, only a very crude analysis can be made. A compilation of published nitrogen budgets has been done by Nilsson (1985) (8), and is shown in Table 2. From these data one gets the subjective impression, that a bulk deposition of nitrogen exceeding approximately 0.5 g N m^{-2} yr^{-1} may be connected with a NO_3^- leaching in the order of 30-60% of the bulk deposition input, but as can be seen in the table there are several exceptions. The pattern must inevitably be confused by differences in the initial nitrogen status within the ecosystem (19) and also differences in the total nitrogen deposition, which are not obvious from the bulk deposition measurements.

As to the initial nitrogen status, a high net mineralization of NH_4^+ is one necessary prerequisite for nitrification. The rates of these two microbiological processes depend on the substrate quality (litter type etc.) but also on soil temperature and soil moisture. Temperature may be a severely limiting factor in the central and northern parts of the country, so there may indeed be a spatial coincidence between unfavourable conditions for mineralization and nitrification on the one hand and low nitrogen deposition on the other.

From this very restricted material, it seems as if a bulk deposition in the order of 0.5 g N m^{-2} yr^{-1} or less is connected with a low NO_3^- leaching amounting to only a few percent of the bulk deposition.

This is of course not a proof of any immediate casual connection between the nitrogen deposition on the one hand and the nitrification and nitrate leaching on the other, but may give a very rough indication of what the permissible nitrogen deposition might be.

In order to get more accurate estimates of the permissible nitrogen deposition, the first thing we have to know is how high the nitrogen deposition actually is. This means that the methods for estimating the dry nitrogen deposition must be improved. Second, a quantitative model of the soil nitrification rate is needed. At the curren tstate of knowledge, one can only make qualitative predictions, concerning the likelihood of nitrification under given environmental conditions. It should be stressed that as far as unfertilized boreal forests are concerned climatic and/or nutritional constraints will dampen the nitrification rate, to a much higher extent than in regions further to the south such as southern Sweden or Denmark, under a given nitrogen deposition regime. Third, we need much more knowledge concerning the gaseous nitrogen losses from forest ecosystems. While it is comparatively easy to get good figures on e.g. potential denitrification, it is extremely difficult to estimate the actual nitrogen loss per unit area and time.

The effects of atmospheric deposition of sulphur and nitrogen compounds in the Netherlands have been recognized as being extremely serious. For this reason government policy has for several years now more or less focused on the establishement of deposition limit values for sulphur and nitrogen compounds. Some examples of the effects in the Netherlands:

- Of all Dutch forests 50% has a reduced vitality. About 13% is badly affected and 2% is dead or dying (1985 data). In 1984 the affected, badly affected and dead/dying areas were 49%, 8% and 1.4% respectively.

- In over 25% of the total Dutch area of heathland and characteristic heather vegetation is being chocked by grasses, due to nitrogen enrichment of the soil.
- Dutch surface waters are for the greater part influenced by the highly polluted rivers Rhine and Meuse. In these waters the effects of acidification cannot be discerned from other factors.

About 5% of the surface water consists of isolated lakes and pools, mainly fed by rain, and of brooks. These waters are poor in tlime and nutrients.

Over 90% of these waters are acid, and over 30% have a pH below 4. Using old measurement data, several empiricla models, as well as biological indicators, it has been shown that most of these waters have acidified in the last 40-50 years.

Cause-effect-relationships

FORESTS

It is generally agreed in Europe that the recent damage to forests is caused by the combination of a great number of stress factors, in which air pollution plays a key role. However, the relative importance of air pollution as well as the composition of air pollution greatly differs over Europe. For the Dutch situation it is getting clearer and clearer that nitrogen compounds are extremely important. This is illustrated by the fact that in concentration areas of intensive livestock raising forest damage is much more severe than in other areas.

Throughfall measurements in coniferous forests show that in the Wadden area deposition of NH_4^+ is about 1 kmole ha^{-1} yr^{-1}, while in Brabant (a concentration area of intensive livestock raising) deposition measured as throughfall is 10-20 kmole ha^{-1} yr^{-1}. This very high deposition results in enhanced NH_4+/K^+ and NH_4+/Mg^{2+}-ratios in the soil.

Experiments with artificial rain, conducted in a greenhouse, show that an ammonium deposition of 2500 mole ha yr^{-1} (500 umole 1$^-$ in the rainwater) results within six months in an NH_4^+/K^+ ratio of 7 and an NH_4^+/Mg^{2+} ratio of 3.5, where the original undisturbed podzol these ratios were about 1. Field data show that these high ratios have a very strong correlation with reduced vitality of coniferous trees.

The researchers of the University of Nijmegen have launched the hypothesis, that these imbalanced nutrient concentrations in the soil solution cause deficienciens in Mg and K, since the tree roots cannot discriminate between these cations and thus take them up in the proportion in which they are present in the soil solution.

In richer, less acid soils the situation is different. Here the NH_4^+/K^+ and NH_4/Mg^{2+} ratios are not influenced to such a large extent by ammonia deposition, since ammonia in these soils is nitrified and nitrate leaching removes most of the excess nitrogen. This process, however, acidifies the soil, and eventually low soil pH will inhibit nitrification.

In order to keep the ratios of nitrogen to potassium and/or magnesia below 5, total nitrogen deposition should not exceed 1400 moles per ha per year (20 kg N ha^{-1} yr^{-1}). It is however to be expected that even at this deposition level forest ecosystems will become saturated with nitrogen, resulting in leaching of nitrate. If it is assumed that in a saturated forest ecosystem all the deposited nitrogen is leached as nitrate, the critical load based on the nitrate standard for drinking water (50 mg l^{-}) would be 10 kg N ha^{-1} yr^{-1}, while a guide value based on the nitrate guide value (25 mg l^{-1}) would be 5 kg N ha^{-1} yr^{-1}.

A limit value for acid deposition for forests could be based on the toxicity of Aluminum. Aluminum becomes toxic if the ratio of Ca+Mg/Al exceeds the critical value of 1.

Calculations indicate that at a deposition rate of 1400 moles H^+ ha^{-1} yr^{-1} this value is not exceeded in most forest soils.

Possible Role of Heavy Metals

Elevated concentration of elements such as lead in soil and vegetation have been attributed to the combustion of leaded gasoline, coal burning and metal smelting activities, and lead arsenate pesticides. Most studies of the toxicology of lead have focused on human beings. However, there have been some studies linking lead levels to mortality in microorganisms and plants. Besides the direct metabolic effects of heavy metals on plant, animal and microorganism cells, heavy metals can affect many subtle microbial activities and interactions. For example, a concentration of 1,040 ug of lead per gram of soil in the form of lead acetate completely inhibited nitrogen mineralization (20). The microbiota of soils and of the leaf surface of plants from sites heavily contaminated with lead and other heavy metals had a significantly lower species diversity than did soils and plants from noncontaminated sites. Babich and Stotszky (1979) (21) noted that the fungi (Rhizoctonia solani, Botrytis cinerea, Trichoderma aspergillus, Penicillium and Fusarium could be greatly inhibited in pure culture with 50 to 100 micrograms per ml of lead added to their media. In addition, with Trichoderma and Aspergillus, it was found that pH had a profound effect on the mobilization and utilization of lead since medium below pH 5.0 had a significantly greater inhibitory effect when combined with lead than media above pH 5.0.

The accumulation of lead in soils has been documented in many studies. Analyses of soil in industrial, urban, agricultural and natural areas indicate that lead concentrations over the past decade have been increasing. The forest floor has been identified as an import sink for lead, accumulating nearly all of the lead falling on it (4). Recent studies (4) (15) (22,23,24) have noted relatively large amounts and high concentrations of lead in forest floor samples collected at remote areas of the northern and southern Appalachian Mountains. Our analyses indicate that lead levels in the forest floors of some high elevation stands in Vermont and North Carolina are often in excess of 2 g of total lead per square meter of forest floor, with average concentrations of approximately 200 ug Pb g^{-1} soil in spruce/fir forests (4) (15). Occasionally, concentrations of 300 ug Pb g^{-1} of soil occur in the 0^e horizon of those soils (Friedland et al., 1984). The values in the high elevation stands are about four times higher than the corresponding values at low elevation (4). We regard the current levels of heavy metals to be high compared to presettlement background perhaps 10x higher (4).

At present it is an open question whether or not metals which have accumulated in the boreal soils have altered ecosystem or plant processes to a sufficient degree to have participated in conifer mortality. We have seen no convincing evidence that ambient levels of metals have directly or indirectly caused deterioration of red spruce but we see no way to rule out this possibility with confidence.

Possible Natural Causes of Red Spruce Decline

Although the primary purpose of this report is to review the ways in which atmospheric deposition could be involved in the anomalies observed in forests, it is important that we do not neglect the possibility that the North American spruce deterioration phenomenon could be a result of natural factors. In this regard, we find the present evidence equivocal and the hypotheses would be extremely difficult to test.

Widespread mortality of selected forest species have been observed before at times, and in places where pollution stress was probably not a factor. Declines of western white pine (northwest U.S., 1930's), and yellow birch (1940's and 1950's, Nova Scotia) are examples (25). In the case of western white pine, extensive mortality followed periods of drought, and marked growth suppression. Causality has been linked to drought and predisposing site factors in the case of western white pine, and no clear cause for birch decline has been established (25). We reported that the occurrence of widespread drought in the Northeast during the early to mid-1960's corresponded to the compression of tree rings which we suggested signaled the beginning of spruce decline (4). With findings of declining spruce on Mt. Mitchell where there appears to be no relationship to low precipitation (22) it appears that drought alone cannot explain the anamolous growth and mortality in spruce. In Germany forest damage became more apparent in or after 1976, a very dry year, and initial work suggested that drought could be involved. The current literature suggests agreement that drought is a secondary factor in German forest decline.

The possibility that there is a biotic agent which is the primary cause still exists, but seems remote because trained investigators have examined dead and dying spruce over the past two decades and only secondary fungal pathogens have been identified in the affected stands. Possibilities such as a virus cannot be readily ruled out, but research has not been done in the U.S. to test for that possibility.

Studies Concerning the Incidence of Forest Decline on Three Continents

For the past 3-years Dr. Robert I. Bruck has undertaken as a research objective - to visit altitude spruce-fir ecosystems throughout North America, Europe and Asia to determine whether or not there is a consistant incidence of forest decline in those areas. Beginning in 1983 permanent observation plots were established in the Black Forest of W. Germany, the southern Appalachian Mountains, the Mount Hood area of Oregon's Cascade Mountains, the Gothic Mountain-Gunnison area of the Colorado Rocky Mountains, the Alaska Range surrounding Mt. McKinley in Alaska and the Mt. Everest Solu-Khumbu region of the Himalayas of Asia. High elevation boreal montane conifer stands were selected in each one of these regions to represent a "typical" western facing aspect for each respective sampling site. Upon plot establishment using techniques similar to the southern Appalachian mountain survey dominant and co-dominant trees were rated for their physical condition or appearance and increment cores selected from certain individuals for dendrochronological analysis. In addition, surface soil samples 0-3 centimeters were collected using a mass per unit area measurement for the determination of nutrients and toxic metals.

Figure 23 illustrates a summary of the average percent of symptomatic trees e.g. those trees exhibiting more than 11% visible defoliation from the six regions that were explored. Through the assistance of colleagues studying the forest decline (Waldsterben) syndrome in West Germany it was determined that approximately 49% of trees in the area of the Black Forest of West Germany exhibited some symptoms of Waldsterben indicating that these fell into the greater than 11% defoliation category. Studies conducted by the two authors of this testimony in the southern Appalachian mountains have indicated that on west facing slopes approximately 38% of all trees scored are categorized as being in the decline category of greater than 11% defoliation. Quite contrary to the observations made in both the southeastern United States and West Germany, observations from the Cascades of Oregon, the Rocky Mountains of Colorado, and Alaska range of Alaska, and the Mt. Everest region of the Himalayas indicated that between 2 and 9% of all trees exhibited visual decline symptoms. It must be remembered that these decline symptoms include stress from all biotic diseases and insects present on these sites. We would expect that from the natural endemic or background levels of pest and pathogens in the environment that there would be between 5 and 10% stressed individuals exhibited on all sites. The relative health of particularly the Himalayan forests was unusual to observe.

Figure 24 illustrates the average 5 year combined annual radial increment measurements of growth form trees from the same regions as previously described in the forest decline symptomatology (Figure 1). The only exception is that relatively high elevation trees (above 1,500 meters) from the Calcarius Alps of southern Germany were used for increment core analysis. It is interesting to note that for the areas of West Germany and the Southern Appalachian mountains during the period of 1955 to 1960 an abrupt decrease (shift to lower annual radial increments) was observed. The annual increments observed in this preliminary survey of all other sites illustrate a continuous normal growth pattern. In fact for the sites of Alaska, the rocky Mountains, and the Himalayas there appears to be a slight however not statistically significant increase in the annual growth increments from approximately 1960 to the present time. Some investigators have speculated that increased enrichment of transglobal carbon dioxide may account for differences in vegetative adaptation and growth patterns particularly as ramified in pristine non-polluted regions.

Figure 25 illustrates surface soil lead accumulation in the 0-3 centimeters strata of soils collected from all six test sites. Lead was used as an indicator of surface soil organic horizon toxic metal accumulation because it is usually firmly bound within the organic matrix and hence is not very mobile. High loadings of lead were observed usually above 400 milligrams per kilogram in many areas of the Alps of West Germany. High readings for certain areas of the southern Appalachian mountains were consistantly above 200 milligrams per kilogram in these organic horizons. Again, it was interesting to note that the Cascades were accumulating usually less than 50 milligrams per kilogram, the Rocky mountains less than 25 milligrams per kilogram, the areas of the Alaska range accumulated less than 10 milligrams per kilogram, while in the Himalayas surface organic horizon lead was barely detectable. The purpose of Figure 30 is not to illustrate the accumulation of highly phytotoxic metals, as information dealing with the phytotoxicity of most heavy metals is not available at this time; but rather to illustrate that areas in which large amounts of heavy metals are accumulating probably are indicative of areas in which high anthropogenic pollution deposition is generally occurring. Therefore surface soil heavy metal contamination particularly down wind of major point source polluters are generally good indicators of total atmospheric deposition fluxes taking place within the region.

Many scientists have speculated that the reason for high altitude accumulation of anthropogenic pollutants may be attributed to direct cloud impaction on these mountain sites. Data from the Calcarius Alps indicate that cloud impaction takes place approximately 70-100 days per year. Data from the southern Appalachian mountains indicates that cloud impaction is a common event generally taking place more than 250 days per year while the Cascades of Oregon are also often bathed in clouds in excess of 200 days per year. Cloud interception data for the Rocky Mountains indicate that events in excess of 80 days per year are common however, no data is available at this writing for the Alaska range or the Mt. Everest region of the Himalayas. Atmospheric chemists have indicated that pollutants contained in cloud moisture may be the single most important contributor to montane ecosystem pollutant deposition.

The three figures just presented are not meant to form a data base that will yield conclusive evidence that anthropogenic pollution is or is not involved in forest decline syndromes, however, it is most interesting to note that in areas where known heavy anthropogenic deposition takes place trees are in fact statistically more symptomatic than trees from non-polluted areas, trees from polluted areas are in fact significantly more suppressed in terms of their growth rates over the past 25-30 years as compared to non-pollutant sites and surface soils have in fact accumulated lead, often an order of magnitude above that of non-polluted region soils. These data do not prove cause and effect relationships but rather formulate a broad correlative base in which we can compare some major silvicultural and physical characteristics of these high altitude northern hemisphere forest. Although, this preliminary survey is severely limited in both its scope and depth, particularly with respect to drawing conclusions about anthropogenic deposition, it does serve as a valuable set of data to make some preliminary comparisons among and between similar types of ecosystems found throughout the world. It is also important to emphasize that air pollution comes in many and varied forms. Wet deposition of acids, toxic and nutrient elements and compounds, dry deposition of gases and aerosols, and gaseous deposition of various hydrocarbons gases and other toxic and nutrient compounds from an atmospheric "vegetable soup" particularly in industrialized areas of the world. It is not appropriate at this time to point fingers at specific pollutants and their potential interactions with the above data because information is not available to prove or even establish general cause and effect hypotheses at this time.

SUMMARY AND CONCLUSIONS

It is very apparent from current data sets that a disease syndrome as complex and as wide spread as the Waldsterben in Central Europe and forest decline in eastern North America requires a comprehensive and multi-staged response. It is most unfortunate that "acid rain", is still regarded by many as the major component of harmful damage to forests, while ignoring the dozens of other potentially harmful compounds which are present. Control efforts have centered on sulfur dioxide almost exclusively and to a lesser extent on nitrogen oxides. It is increasingly clear that whatever combination of pollutants may be affecting North American and European forests they are probably not the same agents that are acidifying lakes and streams in those same regions. Although the bill at hand today that will initiate a significant reduction in both SO_2 and NO_x emissions is important, it should and must be recognized that battling the potential agents of forest decline is a much more complicated and far reaching process. Comprehensive research programs have been and continue to be established by the United States Environmental Protection Agency, and the USDA Forest Service. These efforts are meant to categorize and quantify both natural and anthropogenic influences on potentially affected and already affected forest ecosystems. Only through a comprehensive and integrated program dealing with the multidimensional aspects of forest ecosystem perturbation can we ever hope to come up with a foundation for cause and effect relationships of airborne chemicals and forest stress.

Acid rain principally caused by emissions of sulfur and nitrogen oxides has been used as the "catch all" phrase by environmentalists pressing for changes in pollution control strategies and by governments as an excuse to do nothing or very little about the broad problems of air pollution. This continuing controversy camouflages the real picture i.e. that pollution has multiple causes and multiple effects, acidification being just one of them. Although there are many good and defensible reasons for reduction in SO_2 and NO_x emission, at this time it is difficult for any scientist to show conclusive evidence to support that these emissions are causal in the forest decline syndromes. The "one pollutant at a time" regulatory approach we do not believe will suffice in tackling this particular problem. The issue of trans-boundary pollution will continue to be a difficult and perhaps bitter issue in the coming years if comprehensive air pollution control strategies are not formulated among and between governments. The ultimate solution will most likely depend on a narrowing of the gap between rhetoric and that of scientific reality. We would urge the Congress of the United States to invest its time and money in sound environmental management plans and on balancing short term interests against long term environmental policies. We all realize that the cost that may be related in controlling pollution in a broad spectrum way are high. The costs of not doing so could well be more than we can all afford as a society.

REFERENCES

1. Johnson, A. H., and T. G. Siccama. 1983. Acid deposition and forest decline. Environm. Sci. Technol. 17:294a-305a.

2. Conkey, L. E. 1982. Eastern U.S. Tree-ring Widths and Densities as Indicators of Past Climate. Ph.D. Thesis, Department of Geosciences, Univ. of Arizona, Tucson. 204 p.

3. Johnson, A. H., and T. G. Siccama. 1983. Spruce decline in the northern Appalachians: evaluating acid depositin as a possible cause. In Proc. Annual Meeting of Technical Assessment of Pulp and Paper Industry. March. Atlanta, GA.

4. Johnson, A. H., T. G. Siccama, and A. J. Friedland. 1982. Spatial and temporal patterns of lead accumulation in the forest floor in the northeastern U.S. J. Environ. Qual. 11:577-580.

5. Johnson, A. H., T. G. Siccama, R. S. Turner, and D. G. Lord. 1984. Assessing the possibility of a link between acid precipitation and decreased gorwth rates of trees in the northeastern U.S. In R. A. Linthurst, eds., Direct and Indirect Effects of Acidic Deposition on Vegetation. Acid Precipitation Series, Vol. 5. Butterworth, Boston, MA.

6. Johnson, A. H., T. G. Siccama, D. Wang, R. S. Turner, and D. G. Lord. 1981. Recent changes in patterns of tree growth rate in the New Jersey pinelands: A possible effect of acid rain. J. Environ. Qual. 10(4):427-430.

7. Baes, C. F., and McLaughlin, S. B. 1984. Trace elements in tree rings: Evidence of recent and historical air pollution. Science 224:494-97.

8. Nilsson, S.I. 1985. The acidification sensitivity of Swedish forest soils. - An analysis pertaining to concentration, flows and stores of base cations and aluminium. - National Swedish Environment Protection Board PM 1979. 61 pp.

9. Ulrich, B. 1985. Interaction of indirect and direct effects of air pollutants in forests. In C. Trozanowsky (ed.). Air Pollution and Plants. VCH Publishers, Deerfield Beach, FL. 33442.

10. Ulrich, B. 1983. Soil acidity and relatins to acid deposition. In B. Ulrich and J. Pankrath, eds., Effects of Accumulation of Air Pollutants in Forest Ecosystems. D. Reidel Publishing Co., Hingham, MA.

11. Bauch, J. 1983. Biological alterations in the stem and root of fir and spruce due to pollution influences. In Workshop on the effects of Accumulation of Air Pollutants in Forest Ecosystems. D. Reidel Co., Hingham, MA (In press).

12. Prinz, B. G., H. M. Krause, and H. Stratmann. 1982. Forest Damage in the Federal Republic of Germany. Landesanstalt fur Immissionsschultz des Landes Nordrheinwestfalen, Essen. LIS Rept. No. 28. 144 pp.

13. Friedland, A. J., G. J. Hawley, and R.A. Gregory. 1985. Investigations of nitrogen as a possible contributor to red spruce (Picae rubens Sarg.) decline. Air Pollutants Effects of Forest Ecosystems. May 8-9, 1985. The

Acid Rain Foundation, 1630 Blackhawk Hills, St. Paul, MN. 55122.

14. Friedland, A. J., and A. H. Johnson. 1985. Lead distribution and fluxes in a high-elevator forest in Northern Vermont. J. Environ. Qual. 14:332-336.

15. Friedland, A. J., A. H. Johnson, and T. G. Siccama. 1984c. Trace metal content of the forest floor in the Green Mountains of Vermont: Spatial and temporal patterns. Water, Air, and Soil Pollution. 21:161-170.

16. Lovett, G. Reiners, W. R., and Olson, R. K. 1982. Cloud droplet deposition in a subalpine balsam fir forest: hydrological and chemical inputs. Science 218:1303-1304.

17. van Breemen, N., Mulder, J. & Driscoll, C.T. 1983. Acidification and alkalization of soils. - Plants and Soil 75:283-308.

18. Benarie, M. & Munn, R.E. 1980. Rapporteurs Summary. A. Wet and dry deposition, including melting phenomena and snowpack chemistry. In: Hutchinson, T. & Havas, M. (eds.) Effects of Acid Precipitation on Terrestrial Ecosystems pp. 579-582.

19. Agren, G. 1983. Model analysis of some consequences of acid precipitation on forest growth. - National Swedish Environmental Protectin Board Report PM 1636:233-244.

20. Liang, C. N., and Tabatabai, M. A. 1977. Effects of trace elements on nitrogen mineralization in soils. Environ. Pollut. 12:141-147.

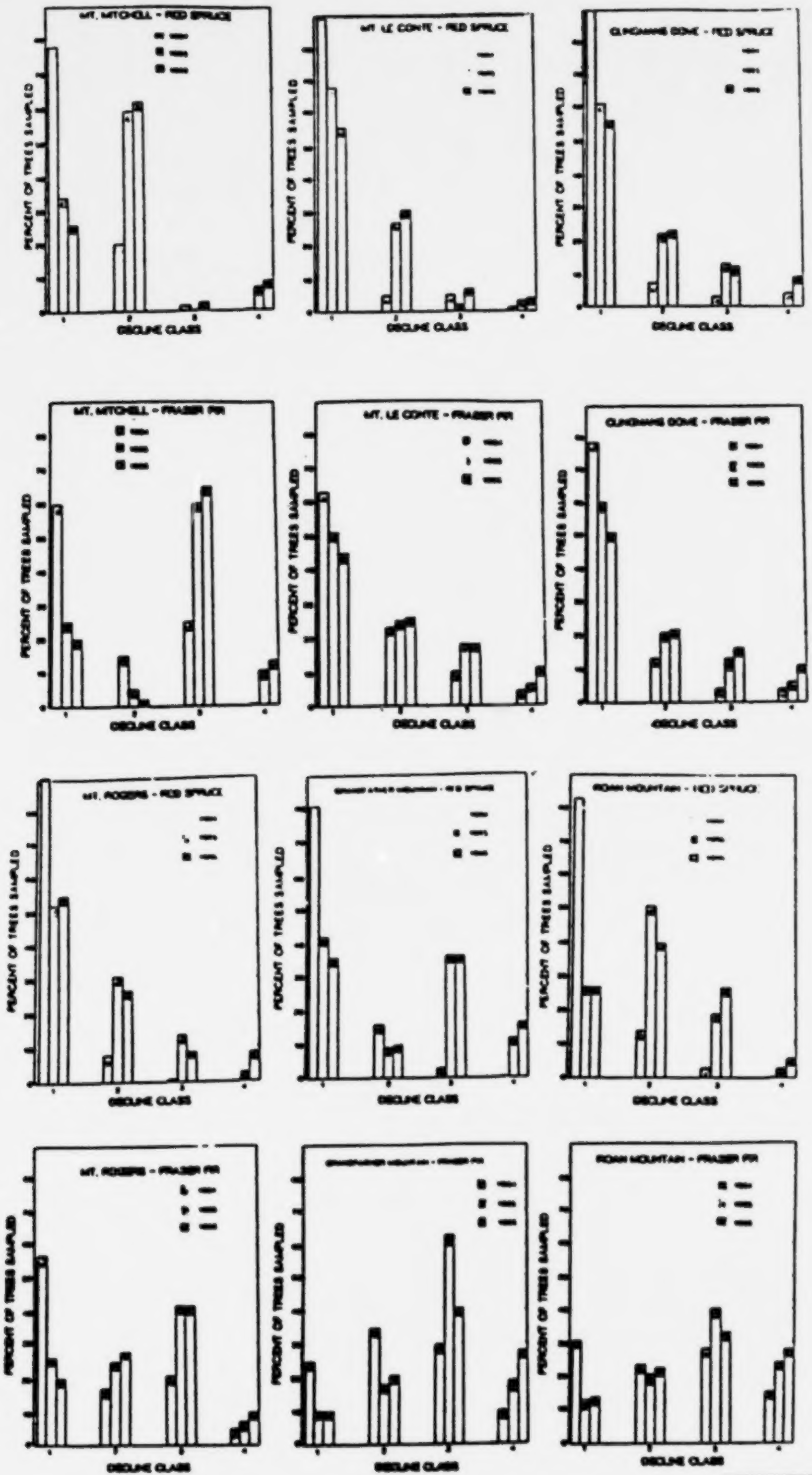
21. Babich, H., and Stotsky. 1979. Environmental factors that influence the toxicity of heavy metal and gaseous pollutants to microorganisms. Crit. Rev. Microbiol. 8:99-145.

22. Bruck, R. I. 1984. Decline of montane boreal ecosystems in central Europe and the southern Appalachian Mountains. TAPPI Proc. 1984:159-163.

23. Bruck, R. I., and S. Meier. 1984. Effects of simulated acid rain on ectomycorrhizae of loblolly pine. NAPAP Peer Review Meeting Proceedings, Asheville, NC, Nov. 1984. 10 pp.

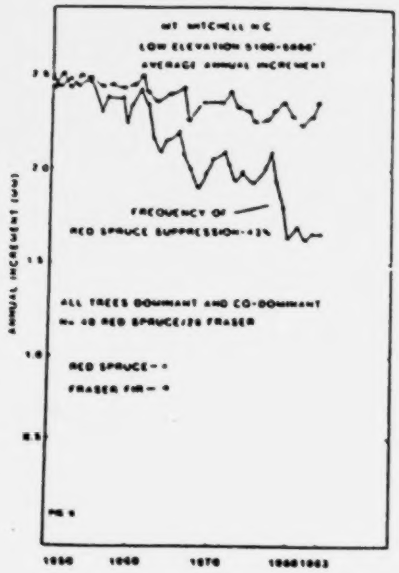
24. Bruck, R. I., S. R. Shafer, and A. S. Heagle. 1981. Effects of simulated acid rain on the development of fusiform rust on loblolly pine. Phytopathology 71:864.

25. Manion, P. D. 1981. Tree disease concepts. Prentice-Hall, Englewood Cliffs, NJ.

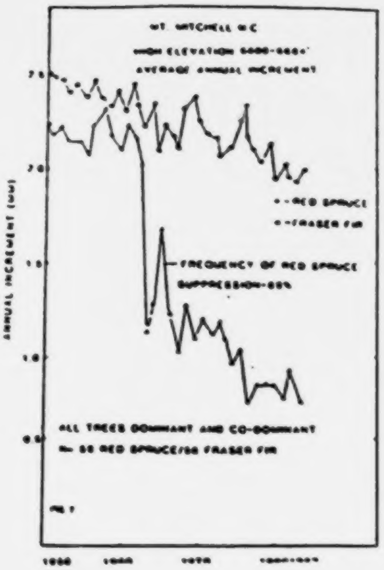


Reproduced from best available copy.

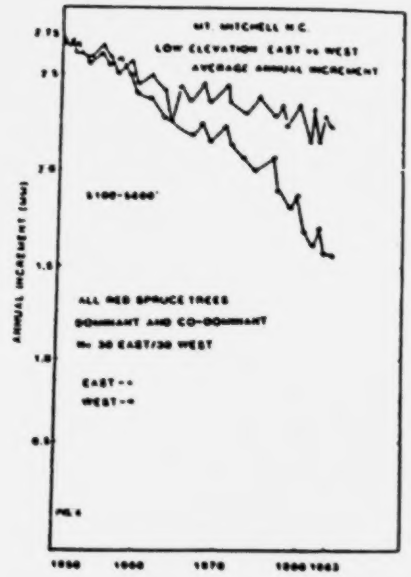
Figures 1-11. Decline class ratings for Fraser fir and Red Spruce during spring assessments of 1984, 1985, 1986. Class one- 0-10% defoliation, Class two- 11-50%, Class three- 51-99%, and Class four- Dead.



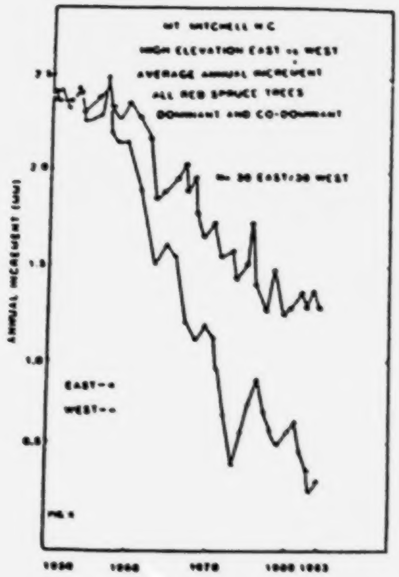
Raw ring-width data for 1984 increment core survey on EPA plots for low-elevation red spruce stands on Mt. Mitchell, N.C.



Raw ring-width data for 1984 increment core survey on EPA plots comparing high-elevation red spruce and Fraser fir ring compression for Mt. Mitchell, N.C.

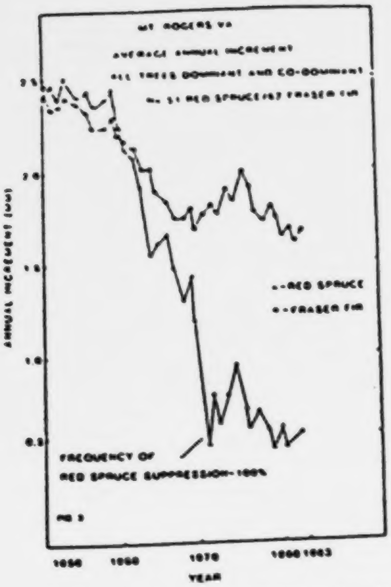


Raw ring-width data for 1984 increment core survey comparing red spruce at low-elevation east vs. west aspects, on Mt. Mitchell N.C.

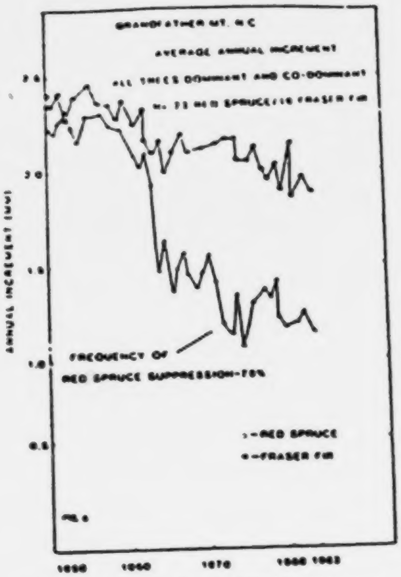


Raw ring-width data for 1984 increment core survey comparing red spruce at high-elevation east vs. west aspects for Mt. Mitchell, N.C.

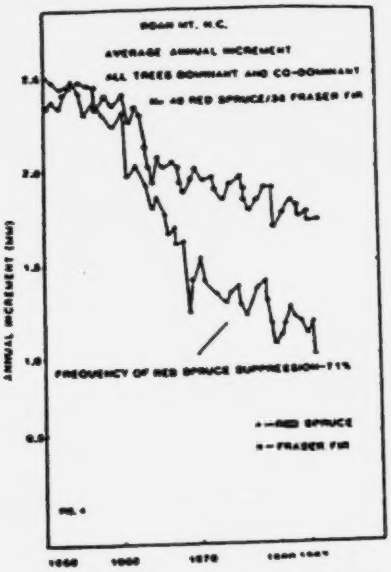
Figures 13-19. Increment core analysis.



Raw ring width data for 1984 increment core survey on EPA permanent plots for Mt. Rogers VA.



Raw ring width data for 1984 increment core survey on EPA plots for Grandfather Mt., N.C.



Raw ring width data for 1984 increment core survey on EPA plots for Roan Mt., N.C.

Figures 13-19. Increment core analysis.

Table 1.

Chemical composition of Fraser fir needles as a function of flush year, for samples collected at the end of the 1984 growing season. Values given are means (+/- standard deviation) for all trees sampled (n=41).

			Flush Year			
Element	1984		1983		1982	
	%					
N	1.54^{a*}	(0.16)	1.50^{a}	(1.30)	1.37^{b}	(0.13)
P	0.18^{a}	(0.03)	0.15^{b}	(0.02)	0.13^{c}	(0.02)
S	0.10^{a}	(0.02)	0.10^{a}	(0.02)	0.09^{a}	(0.01)
Ca	0.34^{a}	(0.11)	0.44^{b}	(0.11)	0.47^{b}	(0.12)
Mg	0.089^{a}	(0.018)	0.081^{b}	(0.019)	0.059^{c}	(0.015)
K	0.53^{a}	(0.10)	0.43^{b}	(0.08)	0.37^{c}	(0.06)
	mg/kg					
Cu	4.01^{a}	(0.63)	4.08^{a}	(0.48)	3.60^{b}	(0.48)
Fe	77^{a}	(23)	126^{b}	(56)	131^{b}	(51)
Mn	460^{a}	(230)	560^{a}	(240)	540^{a}	(240)
Zn	30^{a}	(8)	32^{a}	(8)	29^{a}	(8)
Co	0.13^{a}	(0.06)	0.11^{a,b}	(0.05)	0.10^{b}	(0.04)
Al	310^{a}	(140)	360^{a}	(100)	360^{a}	(120)
Pb	0.65^{a}	(0.41)	2.06^{b}	(1.28)	2.78^{b}	(1.09)

* Means in rows followed by the same letter are not significantly different at the 0.05 level.

Table 2.

Chemical composition of Red Spruce needles as a function of flush year, for samples collected at the end of the 1984 growing season. Values given are means (+/- standard deviation) for all trees sampled (n=30).

			Flush Year			
Element	1984		1983		1982	
	%					
N	1.05^{a*}	(0.10)	1.14^{a}	(0.13)	1.07^{b}	(0.09)
P	0.13^{a}	(0.02)	0.12^{b}	(0.02)	0.10^{c}	(0.01)
S	0.07^{a}	(0.01)	0.07^{a}	(0.01)	0.08^{a}	(0.02)
Ca	0.14^{a}	(0.03)	0.22^{b}	(0.06)	0.28^{b}	(0.07)
Mg	0.069^{a}	(0.011)	0.066^{a}	(0.015)	0.056^{b}	(0.021)
K	0.56^{a}	(0.11)	0.46^{b}	(0.09)	0.43^{c}	(0.10)
	mg/kg					
Cu	3.35^{a}	(0.49)	2.84^{b}	(0.36)	2.73^{b}	(0.42)
Fe	52^{a}	(30)	58^{a}	(29)	66^{a}	(20)
Mn	520^{a}	(190)	670^{b}	(250)	670^{b}	(220)
Zn	24^{a}	(3)	14^{a}	(4)	17^{a}	(7)
Co	0.17^{a}	(0.08)	0.17^{a}	(0.09)	0.13^{a}	(0.07)
Al	91^{a}	(36)	133^{b}	(98)	155^{b}	(52)
Pb	0.5^{a}	(0.2)	0.63^{a}	(0.41)	1.00^{b}	(0.40)

* Means in rows followed by the same letter are not significantly different at the 0.05 level.

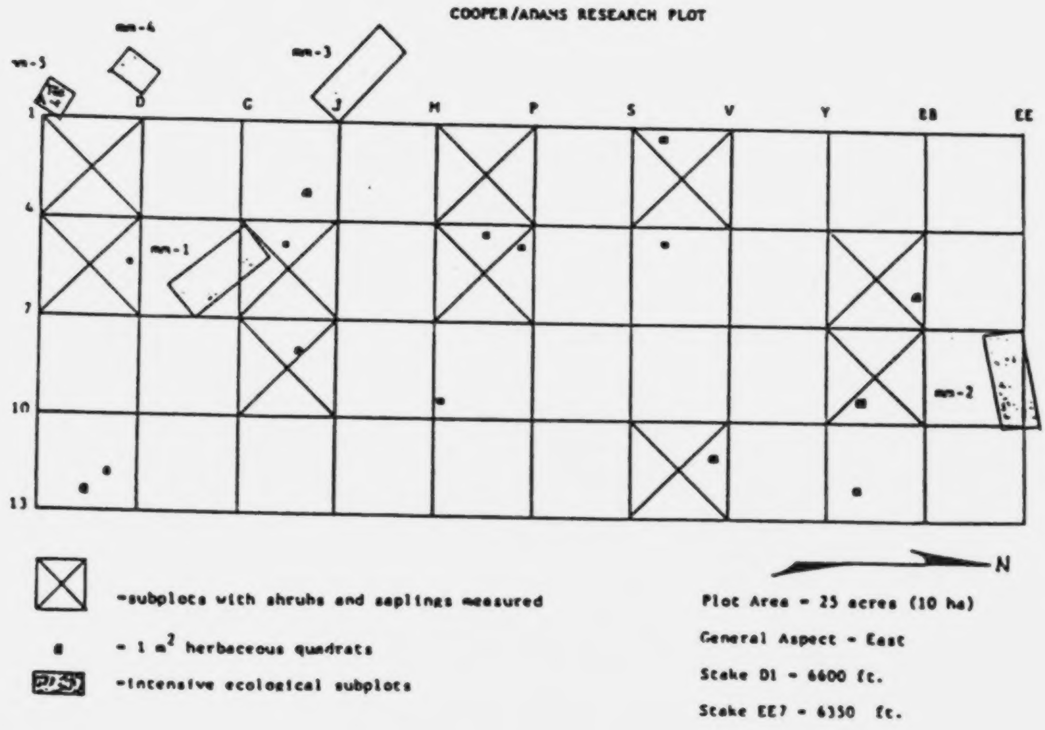

COOPER/ADAMS RESEARCH PLOT
mm-5
mm-4
mm-3
mm-1
mm-2
D
G
J
M
P
S
V
Y
BB
EE
1
4
7
10
13
N
=subplots with shrubs and saplings measured
= 1 m² herbaceous quadrats
=intensive ecological subplots
Plot Area = 25 acres (10 ha)
General Aspect = East
Stake D1 = 6600 ft.
Stake EE7 = 6350 ft.

Figure 20. Map of Cooper/Adams plot layout. Line A begins the transect at 6,550', and ends at line EE at 5,470'.

TREE DATA

Mount Mitchell - Cooper/Adams

Subplot - 2

Upper Canopy (Live)	1958	1986
Mean Fir Stems	18.1	5.3
Mean Spruce Stems	2.1	0.5
Mean Ash Stems	1.1	4.8
Mean Birch Stems	---	1.2
Lower Canopy (Live)		
Mean Fir Stems	---	57.5
Mean Spruce Stems	0.2	0.1
Mean Ash Stems	---	1.8
Mean Mt. Maple Stems	---	0.3
Mean Birch Stems	---	0.4
Mean Rhodo. Stems	0.2	---
Total # Stems/Ha	1830	6470
Percent Upper Canopy	97.2%	2.1%
Percent Lower Canopy	1.3%	96.5%

HERB SUMMARY

Mount Mitchell - Cooper/Adams

Subplot - 2

Herb Genera	Quadrat (F) 1958	Quadrat (F) 1986
Rubus spp.	--	100
Oxalis spp.	70	40
Aster acuminatus	40	--
Dryopteris	20	--
Trillium	40	--
Athyrium	50	--
Hylocomium	100	--
Sorbus	10	--
Lycopodium	50	--
Atrichum	40	--
Dicranum	10	--
Hypnum	10	--
Chelone	20	--
Clintonia	10	--
Viburnum spp.	10	--
Carex spp.	--	100
Acer spicatum	10	--
Monotropa	10	--

MOUNT MITCHELL
COOPER-ADAMS PLOT SURVEY

Tree Statistics (Canopy)

Basal Area (Ft^2/Acre)

	Fraser Fir		Red Spruce	
	1958	1986	1958	1986
Plot 1	86.67	12.62	14.44	8.57
Plot 2	234.77	21.52	134.85	12.47
Plot 3	77.34	17.48	19.59	3.22
Plot 4	112.97	11.88	15.48	2.35
Plot 5	253.67	139.92	139.56	19.42

Tables 3-5 . Summary of representative data from Cooper/Adams plots. Live overstory stems, Basal Area, and species diversity have all dramatically decreased from 1958 to 1986.

Reproduced from best available copy.

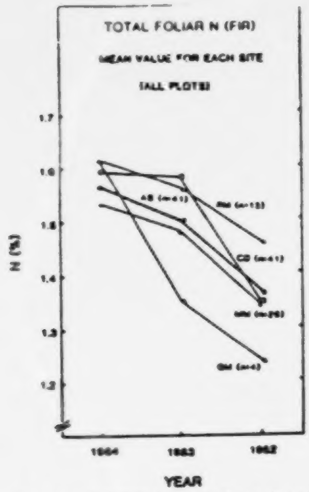


Figure 21. Mean total N (Fir) for Fraser fir as a function of flush year for all sites combined (AS) and for mountain location sampled (GM-Grandfather Mt., NC; RM-Roan Mt., NC; MM-Mt. Mitchell, NC; CD-Clingman's Dome, GSMNP).

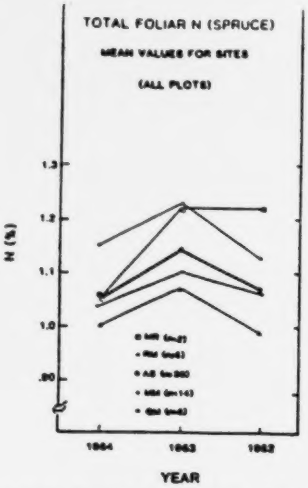


Figure 22. Mean total N (Spruce) for red spruce as a function of flush year for all sites combined (AS) and for each mountain location sampled (GM-Grandfather Mt., NC; RM-Roan Mt., NC; MM-Mt. Mitchell, NC; MR-Mount Rogers, VA).

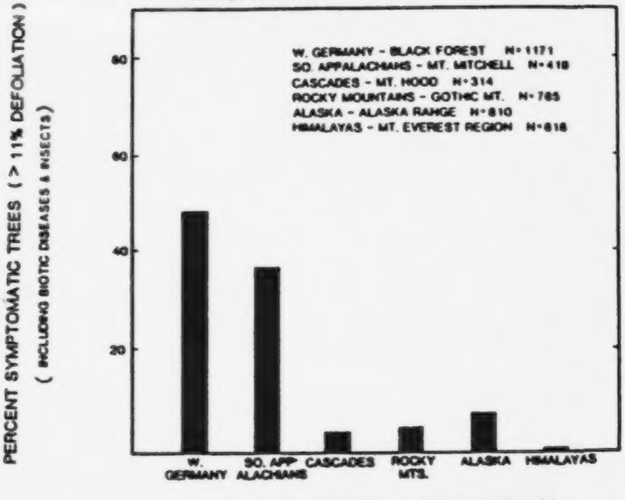


Figure 23. Percent of symptomatic trees observed in boreal montane forest ecosystems from six regions on 3 continents. Trees exhibiting significant defoliation were more common in central Europe and eastern North America.

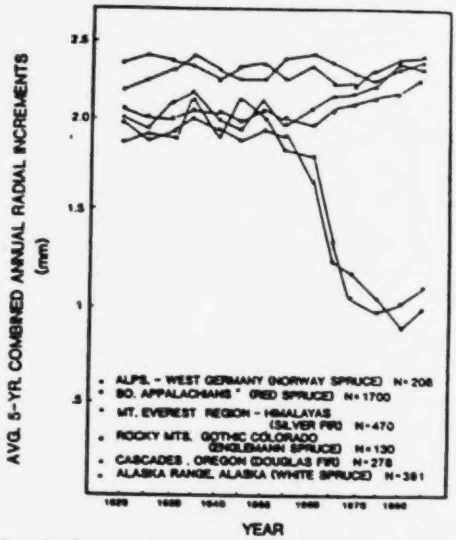


Figure 24. Average of 5-yr. combined annual radial increments taken from six boreal montane ecosystems on 3 continents. All trees were dominant or co-dominant from well stocked undisturbed stands. Trends show significant decreases in annual radial growth rates only in central Europe and eastern North America.

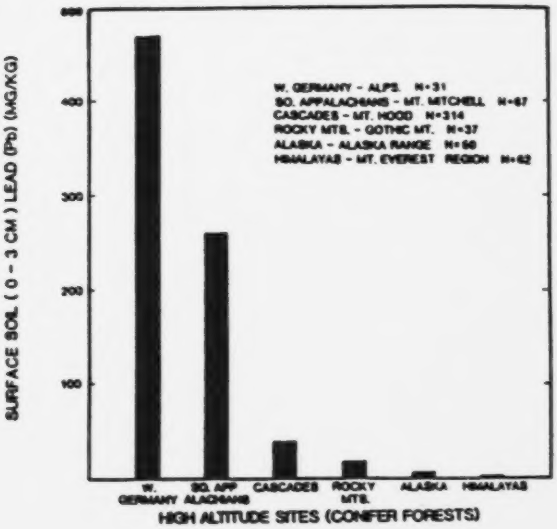


Figure 25. Surface soil lead (Pb) concentrations from boreal montane forest sites in six regions on 3 continents. Significant accumulations are observed only in central Europe and eastern North American sites. High surface soil heavy metal accumulation is probably indicative of overall high anthropogenic pollutant leading.

An Overview of Environmental Issues Related to Nitrogen Oxides in the Atmosphere

by: Charles Hakkarinen
Electric Power Research Institute
Palo Alto, CA 94303

ABSTRACT

Atmospheric nitrogen oxide compounds, including N_2O, NO and NO_2, have been implicated in a variety of environmental effects, both from their direct emission to the atmosphere and their role in the formation of secondary compounds, such as ozone and nitric acid. High temperature fossil fuel combustion is a principal source of atmospheric NO_x emissions, hence the electric utility industry has a strong interest in understanding their environmental fate.

This paper will provide an overview of the current state of scientific knowledge on the transport, conversion and fate of NO_x compounds in the atmosphere. Emphasis will be given to

- the relationship between NO_2/ozone and effects on human health;
- the role of nitrogen compounds/ozone in the perceived decline of some North American forests;
- the contribution of nitrogen compounds to the formation of acidic precipitation; and
- the role of nitrogen oxides (principally, N_2O) in regulating global climate (the "greenhouse effect") and influencing the stratospheric ozone layer (the "polar ozone hole").

The paper will conclude with a brief summary of major research underway at EPRI and elsewhere that addresses environmental issues related to nitrogen oxides.

INTRODUCTION

This paper surveys the state of knowledge and the uncertainties for the environmental effects of nitrogen oxides (NO_x) in the atmosphere. NO_x is defined here to include nitric oxide (NO), nitrogen dioxide (NO_2), nitric acid (HNO_3) and nitrate ion (NO_3^-, without specific reference to a cation). The paper will review the following topics:

- emissions
- contributions to acidic precipitation and ozone formation;
- effects on human health;
- effects of vegetation; and
- effects on climate.

NO_x EMISSIONS

Nitric oxide is the principal species formed in the high temperature combustion of fossil fuels. While some of the nitrogen is derived from nitrogen contained within the fuel, most comes from the molecular nitrogen (N_2) in air. Once emitted to the ambient atmosphere, the NO is rapidly converted to NO_2 by the fast reaction
$NO + O_3 \rightarrow$
NO_2 O_2. Transportation has traditionally been the largest source of NO_x emissions, but in the last 30 years the fractional contribution from fossil fuel combustion in electric utilities has increased substantially. Total emissions have doubled since the end of World War II, although recent data (NAPAP, 1985) suggest that the growth in emissions has slowed considerably. Indirect evidence for this growth curtailment can be seen in measurements of wet nitrate deposition from precipitation chemistry networks. For example, the UAPSP (Utility Acid Precipitation Study Program) network of 20 daily collectors shows no trend in total nitrate deposition for the period 1979-85.

NO_x CONTRIBUTIONS TO ACIDIC PRECIPITATION AND OZONE FORMATION

NO_2 is not very soluble in water and its direct deposition as a gas to vegetative surfaces occurs slowly. The principal pathway by which NO_2 is removed from the atmosphere is by oxidation to nitric acid (vapor) and its subsequent removal by precipitation or surface deposition. As a strong acid nitric acid is the second largest contributor of protons to acidic precipitation at most locations in North America -- sulfur compounds being the greater component. Overall, nitrate contributes about 1/3 of the free acidity in precipitation in industrialized areas, while sulfate contributes about 60%. The remainder comes from chlorides, organic acids, and other miscellaneous sources. Contrary to the "conventional wisdom" that sulfur is mostly responsible for acidity in the eastern U.S. and nitrogen in the west, only monitoring stations in the southern California region exhibit a greater contribution from nitrate than sulfate. Other rural stations in the west follow the proportionality pattern observed at most eastern sites. The highest concentrations of nitrate in precipitation (~ 30 μmoles per liter) are observed at sites in the Boston-Washington megalopolis and at sites near major power/industrial complexes in the Ohio and Tennessee Valleys.

Ozone (O_3) not only is destroyed by reaction with NO, but it is also formed by further reactions of NO_2 with free radicals (from hydrocarbons) in the presence of sunlight. Besides ozone, other complex products of "photochemical smog", such as peroxyacylnitrate, are produced in the process. It is not possible to describe a simple overall relationship between initial NO_x concentrations and ozone concentrations -- the relationship has been the subject of numerous mathematical and smog chamber studies, and is strongly dependent on the mix of reactive hydrocarbons present and the relative ratios of hydrocarbons to NO_x. Most of the photochemical smog modeling to date has been on the urban situation, where NO_x abundance does not appear to be the limiting factor in smog formation. The rural situation, where more of the NO_x emissions from utilities occur today, have not been studied as extensively, in part because instrumentation for routine continuous monitoring lacked sufficient sensitivity to reliably detect the low levels of NO_2 present at ground level. Improved techniques are available today, should another massive rural monitoring program like the Sulfate Regional Experiment of a decade ago be mounted.

With the exception of a few large urban areas, notably Los Angeles and Houston, average ozone concentrations are surprisingly uniform across the U.S. with few variations in the annual average by more than 30%. There can, however, be substantial differences from year to year, reflecting the fact that meteorological conditions play a substantial role in determining ozone concentrations at a given location. This "relative" uniformity in ozone concentrations over large distances may be due to a number of circumstances, including a significant contribution from "background", the "relatively" long lifetime of NO_2 in the atmosphere, permitting thorough diffusion over long distances, and the ubiquity of hydrocarbons from natural and other sources in sufficient quantity to not be rate-limiting in the ozone formation reactions.

EFFECTS OF NO_x ON HEALTH

It is "common knowledge" that some components of photochemical smog (although not necessarily ozone or NO_x) produce eye irritation. And some studies have suggested that NO_2 can contribute to pulmonary disfunction. People with chronic pulmonary disease or asthma were judged to be the most susceptible groups. For this reason, EPRI's Health Studies Program has supported a major research program at the Rancho Los Amigos Hospital in southern California to expose human volunteers to various levels of NO_2. One group consisted of 22 volunteers who suffer from chronic obstructive pulmonary disease (COPD). The second group of 21 volunteers with asthmatic tendencies were exposed to controlled NO_2 concentrations while exercising on a bicycle. One-hour long NO_2 exposures varied from 0 ppm (controls) to 0.5 ppm (a poor air quality condition) to as much as 3.0 ppm -- values well above any expected under ambient conditions. Standardized measurements of lung volume and lung function were conducted before and after the exposures. The investigators found no statistically significant differences in effect to any of the volunteers at any of the exposures.

Admittedly, these results are viewed with some controversy, and there are other health scientists who find conflicting evidence in their own studies. Nevertheless, the findings do suggest that NO_2 alone may not be responsible for lung disfunction. The results do not rule out the possibility that NO_2 is a contributing factor in the presence of some other unidentified component of photochemical smog.

EFFECTS OF NO_x ON FORESTS

Recent studies have found declines in the growth and vigor of some tree species in central Europe and at high elevation sites in eastern North America. Because these declines could not be readily attributed to some known cause (e.g. drought, disease, insect infestation), hypotheses have been suggested that air pollution or acidic deposition may be contributing to the decline. Notable among these unexplained declines is the red spruce population of the northeastern U.S., which, by examination of tree ring widths, appears to have begun a synchronized decline in growth over large areas in the mid-1960's. German scientists had earlier suggested that acidic deposition could mobilize naturally occurring aluminum in soils, which could disrupt nutrient cycles through trees' root systems and prove toxic. Later hypotheses suggested that acidic mists, perhaps in combination with ozone, were damaging cell membranes in leaves and needles and disrupting photosynthesis.

Not only was NO_x implicated through its role in acidic precipitation and ozone formation, but another theory suggests that trees, which receive essential quantities of nitrogen from atmospheric deposition, were receiving too much nitrogen at the end of the growing season. The hypothesis is that the trees do not "harden" sufficiently for the winter and suffer subsequent frost and desiccation damage. The trees lose the damaged one-year-old needles during the following spring and suffer a consequential loss of productivity in the next growing season. Repeated occurrences of this phenomenon could lead to an overall decline in tree growth and vigor. Other hypotheses that have been offered to explain the unexplained declines include secondary infestations, climate stress, and forest management practices. Most investigators now believe that multiple stresses are involved, and the specific effects may be quite varied from tree species to species and among different locations for the same tree species.

There is also evidence that the such declines have occurred in the past and may be part of a larger cycle of forest behavior that is not recognized or understood. As an example, balsam fir trees in the Adirondack Mountains are known to experience a "wave" of dead and dying trees that moves across a forest. Once the wave begins, it is possible to explain further dieback by the stress of exposure to "survivors" in the newly opened canopy. However, the initiation of the fir wave is not fully understood.

EFFECTS OF NO_x ON CLIMATE

It has long been known that the microclimate of cities is quite different from suburban and rural areas. This effect is, however, due more to the production of aerosols from urban emission sources and the heat retention characteristics of the buildings, than to emissions of NO_x. On the global scale, the principal moderators of climate are water vapor and carbon dioxide (CO_2). Fossil fuel combustion is the major man-made source of CO_2 emissions, but represents about half of the total effect of so-called "greenhouse gases" in the atmosphere -- gases that are transparent to incoming short-wave solar radiation but absorb outgoing long-wave radiation at wavelength bands that are not already being absorbed by water vapor. The net effect of these greenhouse gases is to raise the global temperature of the earth's atmosphere.

Number three in importance among the non-CO_2 greenhouse gases (behind methane and Fluorocarbon-11) is nitrous oxide (N_2O). This long-lived gas -- estimated atmospheric lifetime is 100 years -- has an atmospheric concentration of about 300 ppb.

Over the past decade the concentration has been increasing at an average rate of 0.5% per year, a rate too fast to be judged to be solely from natural sources. While its overall contribution to the greenhouse effect remains small (less than 10%), N_2O has also been implicated as a possible contributor to the stratospheric ozone "hole", a significant drop of 30% in ozone concentrations over the South Pole in the Antarctic spring, which has been observed since the late 1970's and appears to be increasing in size and magnitude. The importance of these observations to the earth's climate and environment have not been determined, but they do portend a continuing long-term concern about the effects of increased NO_x emissions to the atmosphere.

The Role of Nitrous Oxide (N_2O) in Global Climate Change and Stratospheric Ozone Depletion

by: Dennis A. Tirpak
U.S. Environmental Protection Agency
Washington, D.C. 20460

ABSTRACT

Several recently completed scientific assessments have concluded that there is a significant potential for global atmospheric change -- climate change and stratospheric ozone depletion -- to occur in the next few decades. Nitrous oxide (N_2O) is a critical element in both issues. Although the problem of global climate change was once synonomous with carbon dioxide, there is growing recognition of the role of other trace gases. Chlorofluorocarbons, N_2O, methane, and other trace gases now account for roughly half of the warming from greenhouse gases in the atmosphere, and by the year 2030 may lead to twice as much warming as from carbon dioxide alone. The U.S. Congress has asked the U.S. Environmental Protection Agency to prepare a report on policy options to stabilize these trace gas concentrations.

This paper will evaluate the role of N_2O in global climate change and stratospheric ozone depletion. It will summarize trends in N_2O concentrations, review our understanding of current and projected emission sources and emission factors, discuss the twin issues of climate change and ozone depletion, and recommend topics for further study.

ATMOSPHERIC CONCENTRATIONS

The mean global concentration of N_2O is approximately 300 parts per billion volume (ppbv) (1). In contrast, carbon dioxide (CO_2) concentrations are three orders of magnitude greater; approximately 345 parts per million volume (ppmv) (1). Concentrations of both gases are increasing at similar rates. CO_2

is increasing at approximately 0.4 percent per year (Figure 1) (1). Observed rates of increase for N_2O range from 0.2 to 0.4 percent per year (2).

Weiss (3), collected separate measurements between 1976 and 1980 at several monitoring stations and aboard oceanographic vessels in the major world oceans. His analysis demonstrated that the tropospheric N_2O concentration was increasing at approximately 0.2 percent, or 0.7 ppbv, per year (Figure 2).

Results from the five globally distributed monitoring stations of the Atmospheric Lifetime Experiment are consistent with the Weiss data. The measured trends at the five network stations are 0.77, 0.27, 0.24, 0.09, and 0.18 percent per year (Figure 3). While the rates of increase appear to be larger in the Northern hemisphere (0.25 to 0.7 percent per year) than in the Southern hemisphere (0.1 to 0.2 percent per year), there is little variation in actual concentrations (1). The North/South interhemispheric mixing ratio is 1.003 (4). If statistically significant, this discrepancy may be due to a growing imbalance between Northern sources and global sinks (1).

Rasmussen and Khalil (5) reported N_2O data for stations in the Pacific Northwest and the South Pole for 1975 to 1985. They find more rapid increases, and fit a linear trend of 1.04 ppbv per year (Figure 4).

Evidence confirming these atmospheric measurements has been obtained from ice cores. These data show that concentrations of N_2O have risen over the last 400 years. Current concentrations are 8 percent higher than in the year 1600 (6). The data show slight increases from 1600 to the mid 19th century, followed by more rapid increases (Figure 5). This change is generally coincident with the onset of the Industrial Revolution.

The atmospheric lifetimes of N_2O and other trace gases linked to global climate change and stratospheric ozone depletion are long (Table 1). N_2O's lifetime is estimated to be 150 years (1). Its only known significant sink is transport to the stratosphere, a process which is slow relative to the current source strength. The implication of this imbalance is that even if emissions are held constant, concentrations will continue to rise for several decades.

CURRENT N_2O SOURCES

N_2O is emitted by natural and anthropogenic sources. Table 2, taken from McElroy and Wofsy in the WMO assessment (1), shows our current estimates of global sources and sinks. Approximately half of total emissions are from soils in the tropics. Oceans are generally thought to be a secondary natural source. Major anthropogenic sources, approximately 31 percent of total emissions, are fossil fuel combustion and biomass burning.

1. Natural sources

Natural emissions of N_2O were once thought to result from the breakdown by bacteria of complex nitrogen compounds into molecular nitrogen. Such reactions occur most often in environments rich with organic debris but with low oxygen content, such as sediments and closed ocean basins. Recent measurements indicate, however, that such environments actually contain very low levels of N_2O, which itself is consumed in the denitrification process (1).

Current theory suggests that natural production of N_2O occurs in oxygen-rich, or aerobic, environments. It appears that the major pathway for N_2O production is primary nitrification, a key step in the aerobic degradation of organic material. This reaction can occur in aerobic soils and waters. (WMO, 1986).

As shown in Table 2, soils are the major natural source. Measurements indicate that N_2O emission rates are far greater for soils in tropical regions. To illustrate the variation in soil emissions for different regions, Table 3 shows some of the soil data. Measurements from forest sites in Brazil, Equador, Puerto Rico, and New Hampshire show that average N_2O fluxes for tropical forests average about $2x10^{10}$ molecules cm^{-2} sec^{-1}, as compared to $1-2 \times 10^9$ molecules cm^{-2} sec^{-1} in New Hampshire (1).

2. Anthropogenic sources

Anthropogenic processes account for roughly one-third of current emissions. Fertilizers were originally thought to be the major anthropogenic source, and were the subject of considerable research in the early 1970's. Recent estimates, however, show that they contribute only a small share of the anthropogenic source strength. Biomass burning in the tropics contributes a similar amount (1).

Combustion is estimated to contribute 85 percent of anthropogenic emissions (1). The utility sector, primarily through oil and coal burning, is estimated to contribute approximately 53 percent of the combustion total, with the industry sector accounting for about 40 percent and household fuels accounting for 6 percent (7).

Combustion-generated N_2O emissions were the subject of a 1986 dissertation by Wei Min Hao (8), and a workshop sponsored by the EPA in February 1986 in Durham, North Carolina. The workshop evaluated measurement issues, the chemical kinetics of N_2O formation and destruction, the relative importance of combustion sources, and preliminary evaluation of control approaches (9).

At the workshop, preliminary evidence was presented which indicated that for coal-fired and oil-fired combustion, N_2O emissions are generally proportional to NO_x emissions. Figure 6 shows results from stack tests conducted on boilers firing coal, coal-oil mixtures, coal-water slurries, oil, and refinery gas. On average, the volume of N_2O emissions is approximately 22 percent of NO_x emissions (9). This evidence suggests that potential future reductions in NO_x, as is mandated by some pending Congressional regulation, would also result in N_2O reductions; however important research and stack testing is needed to confirm these data. Table 4 shows the emission coefficients for both NO_x and N_2O as recommended by Kavanaugh (7).

PROJECTED INCREASES IN N_2O

Atmospheric modellers have generally assumed that N_2O concentrations will continue to increase at historical rates. Proposed scenarios include Ramanathan et al. (10), who project increases of 0.3 percent per year and Wuebbles et al. (11), who suggest an increase of 0.25 percent per year, with a range for evaluating uncertainty of no growth to 0.3 percent per year.

Weiss (3), and Khalil and Rasmussen (12), have projected N_2O concentrations based on extrapolation of source trends. Weiss (3) fits a simple box model which relates the tropospheric rate of increase to an exponentially increasing source strength. Two scenarios are constructed: the "combustion" scenario, in which emissions increase at 6 percent per year, and the "agricultural" scenario, in which emissions increase at 3.5 percent per year. By the year 2000, the atmospheric model indicates that the N_2O concentration will be 5 percent to 7 percent above current values (Figure 7).

Rasmussen and Khalil construct a logistic model with built-in limits to growth in N_2O concentrations. (12). Because of its self-limiting nature, the model shows smaller increases in N_2O concentrations (Figure 8).

The Weiss and Khalil/Rasmussen models represent an advance over the common practice of extrapolating historically observed increases in concentrations. However, they still rely on an extrapolation of the source trends. An integrated model is needed that combines projections of individual source strengths, changes in emissions factors, and changes in the biogeochemical cycles that control the fate of emissions.

Kavanaugh (7) has constructed projections of N_2O emissions and emission factors for combustion. He used the Institute for Energy Analysis/Oak Ridge Associated Universities Long-Term Global Energy Model (13) to project fossil fuel use. Current emission factors were compiled, and possible changes in emission factors considered. For example, emission factors could change as a result of the use of advanced combustion technology in the developing world. Kavanaugh found large increases in N_2O emissions from combustion: a doubling in emissions from 1975 to 2000 and a 44% increase from 2000 to 2025. His results are shown in Figure 9.

N_2O AND GLOBAL ATMOSPHERIC CHANGE

1. Stratospheric Ozone Depletion

Increasing concentrations of N_2O are of concern to EPA because of its important role in stratospheric ozone depletion and global climate change. Table 5 identifies the effects of N_2O and other trace gases both on climate change and ozone depletion.

The stratospheric ozone layer acts as a shield that prevents most harmful ultraviolet radiation (UV-B) from penetrating to the earth's surface. Ozone is naturally created and destroyed in a cycle discovered by Chapman in 1931. The possibility that anthropogenic forces could upset this cycle was first raised in the early 1970's, with concerns about exhaust emissions from the space shuttle and proposed fleets of supersonic transports. Since 1974, there has also been concern that a class of industrial chemicals, chlorofluorocarbons (CFCs), may also lead to stratospheric ozone depletion.

Stratospheric ozone is particularly sensitive to chlorine and nitrogen. CFCs and N_2O are stable enough to reach the stratosphere, where they are photo-dissociated to release chlorine and nitrogen atoms. Both chlorine and nitrogen enter into catalytic cycles, where either atom can destroy thousands of ozone molecules (1). Reductions in the stratospheric ozone layer would allow greater amounts of UV-B to reach the earth's surface. Research has linked UV-B with skin cancer, systemic immune suppression, cataracts, disruption of aquatic and terrestial ecosystems, and welfare damages including polymer degradation and exacerbation of ground level smog (14).

By itself, the odd nitrogen released into the stratosphere from the photolysis of N_2O would enter into catalytic chains that destroy ozone. However, in the presence of chlorine compounds, the odd nitrogen interferes with the chlorine-catalyzed destruction of ozone (Stolarski, personal communication).

Efforts to prevent stratospheric ozone depletion are making rapid headway, both in the U.S. and abroad. In January 1986 the EPA published its Stratospheric Ozone Protection Plan, which calls for enhanced research and analysis aimed at narrowing research gaps, a series of domestic and international workshops to enhance understanding and cooperation, and parallel track domestic and international decisionmaking. By May 1987, EPA will either announce the outline of domestic regulations or will state that there is no need for action. Final rules, if found necessary, will be promulgated in November 1987 (15).

International efforts to protect the stratosphere are being coordinated by the United Nations Environment Programme under the auspices of the Vienna Convention for Protection of the Ozone

Layer. The major world parties seem to be moving together toward a program of significant controls on CFCs.

The EPA hopes that these international controls can be integrated with its domestic decisionmaking, and the efforts are proceeding on parallel tracks. The current official position of the U.S. Government calls for an immediate freeze and long term phaseout of global production of CFC-11, CFC-12, CFC-113, Halon-1211, and Halon-1301, coupled with a periodic review of the strategy and the science (16).

2. Global Climate Change

N_2O is also a radiatively active trace gas (10). By absorbing infrared radiation reflected from the earth's surface, N_2O and other trace gases raise the earth's surface temperature. This "greenhouse effect" is responsible for the hospitable planet on which we live. Without our current atmosphere, the earth's average temperature would be zero degrees Fahrenheit (17).

The "greenhouse" phenomenon first stirred concern in the late 1970's as recognition grew over the increasing concentrations of carbon dioxide. The "greenhouse effect" was largely attributed at the time to fossil fuel combustion. While carbon dioxide still receives the most attention, researchers now recognize the importance of other trace gases (18). Other than carbon dioxide, researchers cite as the most important gases the CFCs, methane, and N_2O.

By 1979, sufficient evidence had accumulated for two panels of the National Academy of Sciences to conclude that increasing concentrations of these greenhouse gases would warm the earth (19, 20). The NAS panels concluded that a doubling of carbon dioxide concentrations, or radiatively equivalent increases in other trace gases, would have a direct effect on the earth's temperature of approximately 1.2 degrees Centigrade (21).

This initial warming would be amplified by climatic feedbacks including changes in stratospheric water vapor, cloud cover, and the earth's reflectivity, or albedo. These feedbacks, estimated the NAS panels, would lead to an increase of approximately 3.0 degrees Centigrade, with an uncertainty range, primarily due to uncertainty in cloud modelling, of 1.5 to 4.5 degrees Centigrade (20).

What remains uncertain is the timing of the warming, which will be delayed somewhat by the oceans, which absorb and then slowly release heat. Testifying before Congress earlier this year, Dr. V. Ramanathan of the National Center for Atmospheric Research stated that a warming of 0.2 to 0.4 degrees Centigrade per decade is likely (22).

The direct effects of N_2O on global temperatures are presented in Ramanathan et al. (10). Using a radiative model with a climatic sensitivity of 2 degrees Centigrade for doubled CO_2 concentrations, Ramanathan et al. project that by the year 2030, increases in N_2O at historically observed rates will cause an increase in equibrium temperature of 0.1 degrees Centigrade (Figure 10).

Recent results from the most advanced climate modelling tools -- the General Circulation Models (GCMs) -- show that the earth's climate sensitivity may be higher than the 1.5 to 4.5 degree Centigrade cited by the NAS. The current GCMs of the Goddard Institute for Space Studies (21), Geophysical Fluid Dynamics Laboratory (23), and National Center for Atmospheric Research (24) all show increases close to the high end, i.e. 4.0 degree Centigrade. Unpublished reports from the GCM of the British Meteorological Office show a warming of 5.2 degrees Centigrade for doubled CO_2 or its radiative equivalent (personal communication, J. Mitchell).

This change in global temperatures expected as a result of greenhouse gases would be on a scale equal to that of the warming that has occured since the last ice age, of about 4 to 5 degrees Centigrade. The effects of such a change would be enormous. Consider the earth of 18 thousand years ago: a cold, dry atmosphere, ice caps over most of North America and oak trees in Florida. Also consider that current projections suggest that we will undergo a similar change in the next 50 to 100 years rather than the 18 thousand years it took for the earth to reach its current climate.

This rapidly changing climate would have important implications for temperature, precipitation, humidity, wind patterns, soil moisture, storm tracks, growing seasons, and sea level. In turn, these physical changes would affect water resources, forests, agriculture, cities, and even business and industry in a manner which is difficult to imagine. EPA has joined the Electric Power Research Institute, Edison Electric Institute, and New York State Energy, Research and Development Agency in one attempt to assess the impacts on electric utility industry operations over the next 20 years. The Agency has also cosponsored several studies to examine the effects of sea level rise on local communities.

At the request of the U.S. Congress, EPA is conducting studies on potential strategies to limit trace gas concentrations, and on the effects of global climate change.

RESEARCH NEEDS

While researchers are fairly confident about the global budget of N_2O, there is considerably less certainty about the relative contribution of the important sources. There is a critical need for more studies to provide reliable estimates of current emissions patterns, and how the activities that govern the sources are likely to change with time. Future energy paths are of particular interest. Kavanaugh, for example, found that the largest uncertainty in projecting combustion emissions resulted from uncertain projections of economic and population growth, and choices of energy technologies, in China and the rest of the developing world.

More than half of current N_2O emissions are from the tropics. There is a need to improve our characterization of current emission sources and emission factors, and to explore the forces that influence development in this region.

To assess future changes in N_2O concentrations, an integrated model should be developed that can consider widely varying scenarios of emission sources, emission factors, and changes in the biogeochemical forces that control the fate of emissions.

Finally, the fundamental forces that control N_2O formation and destruction in combustion have yet to be adequately described. Basic research is needed. The Agency hopes to encourage more research into these fundamentals, and plans to "piggy-back" on ongoing experiments and collect N_2O data when feasible. Emissions must be measured from both stationary and mobile sources under a wide variety of operating conditions.

In summary, both global climate change and stratospheric ozone depletion are international issues which the Agency is attempting to respond to in an integrated, globally-coordinated approach. The U.S. can and is taking a leadership position. Major international programs have been proposed to improve our scientific understanding. The National Aeronautics and Space Administration, National Oceanic and Atmospheric Administration, and the National Science Foundation have prepared the Earth Sciences Program to monitor the globe. The International Geosphere-Biosphere Program is being encouraged by the International Council of Scientific Unions, and the World Climate Program by the World Meteorological Organization. The next decade promises to be an exciting period of exploration which will lead to increased understanding among all nations.

REFERENCES

1. World Meteorological Organization. Atmospheric Ozone 1985: Assessment of our understanding of the processes controlling its present distribution and change. World Meteorological Organization, Geneva, Switzerland, 1986.

2. Khalil, M.A.K., and R.A. Rasmussen. Increase and seasonal cycles of nitrous oxide in the earth's atmosphere. Tellus. 35B: 161-169, 1983.

3. Weiss, R.F. The temporal and spatial distribution of tropospheric nitrous oxide. Journal of Geophysical Research. 86(C8): 7185-7195, 1981.

4. Prinn, R.G., P.G. Simmonds, R.A. Rasmussen, R.D. Rosen, F.N. Alyea, C.A. Cardelino, A.J. Crawford, D.M. Cunnold, P.J. Fraser, and J.E. Lovelock. The Atmospheric Lifetime Experiment. 1. introduction, instrumentation, and overview. Journal of Geophysical Research. 88(C13): 8353-8367, 1983.

5. Rasmussen, R.A., and M.A.K. Khalil. Atmospheric trace gases: trends and distributions over the last decade. Science. 232: 1623-1624, 1986.

6. Pearman, G.I., D. Etheridge, F. deSilva, and P.J. Fraser. Evidence of changing concentrations of atmospheric CO_2, N_2O and CH_4 from air bubbles in Antarctic ice. Nature. 320: 248-250, 1986.

7. Kavanaugh, M. Estimates of future CO, N_2O and NO_x emissions from energy combustion. Atmospheric Environment. 21(3): 463-468, 1987.

8. Hao, W.M. Unpublished thesis, Harvard University, 1986.

9. Lanier, W.S., and S.B. Robinson (eds.). EPA Workshop on N_2O Emission from Combustion. EPA-600/8-86-035. U.S. Environmental Protection Agency, Research Triangle Park, NC, 1986. (NTIS No. PB87-113742.)

10. Ramanathan, V., R.J. Cicerone, H.B. Singh, and J.T. Kiehl. Trace gas trends and their potential role in climate change. Journal of Geophysical Research. 90(D3): 5547-5566, 1985.

11. Wuebbles, D.J., M.C. MacCracken, and F.M. Luther. A proposed reference set of scenarios for radiatively active atmospheric constituents. DOE/NBB-0066. U.S. Department of Energy, Washington, DC, 1984.

12. Khalil, M.A.K., and R.A. Rasmussen. Logistic and other models for the trends of nitrous oxide. In: National Oceanic and Atmospheric Administration. Geophysical Monitoring for Climatic Change. 1985 Annual Report. Volume 12, 1986.

13. Edmonds, J., and J. Reilly. The IEA/ORAU long-term global energy model. Oak Ridge National Laboratory, Oak Ridge, TN, 1985.

14. U.S. Environmental Protection Agency. An assessment of the risks of stratospheric modification. Draft report. U.S. EPA, Washington, DC, 1987.

15. U.S. Environmental Protection Agency. Stratospheric ozone protection plan. Federal Register. 51(3): 1257-1260, 1986.

16. U.S. Environmental Protection Agency. U.S. views on international protocol on stratospheric ozone protection. Available from the Strategic Studies Staff, U.S. EPA, Washington, DC, 1987.

17. Rind, D., and S. Lebedeff. Potential climatic impacts of increasing atmospheric CO_2 with emphasis on water availability and hydrology in the United States. U.S. EPA, Washington, DC, 1984.

18. Seidel, S., and D. Keyes. Can we delay a greenhouse warming? EPA 230-10-84-001. U.S. EPA, Washington, DC, 1983.

19. Charney, J. Carbon dioxide and climate: a scientific assessment. National Academy of Sciences, National Academy Press, Washington, DC, 1979.

20. Smagorinsky, J. (chairman), Carbon dioxide and climate: a second assessment. National Academy of Sciences, National Academy Press, Washington, DC, 1982.

21. Hansen, J., A. Lacis, D. Rind, G. Russell, P. Stone, I. Fung, R. Ruedy, and J. Lerner. Climate sensitivity: analysis of feedback mechanisms. In J.E. Hansen and T. Takahashi (eds.), Climate Processes and Climate Sensitivity. Geophysical Monograph 29. Maurice Ewing Volume 5, American Geophysical Union, Washington, DC, 1984.

22. Ramanathan, V. Testimony before the Subcommittee on Environmental Protection and the Subcommittee on Hazardous Wastes and Toxic Substances of the Committee on Environment and Public Works, U.S. Senate, January 28, 1987.

23. Manabe, S., and R.T. Wetherald. Reduction in summer soil wetness induced by an increase in atmospheric carbon dioxide. Science. 232: 626-628, 1986.

24. Washington, W.M., and G.A. Meehl. Seasonal cycle experiment on climate sensitivity due to a doubling of CO_2 with an atmospheric general circulation model coupled to a simple mixed-layer ocean model. Journal of Geophysical Research. 89(D6): 9475-9503, 1984.

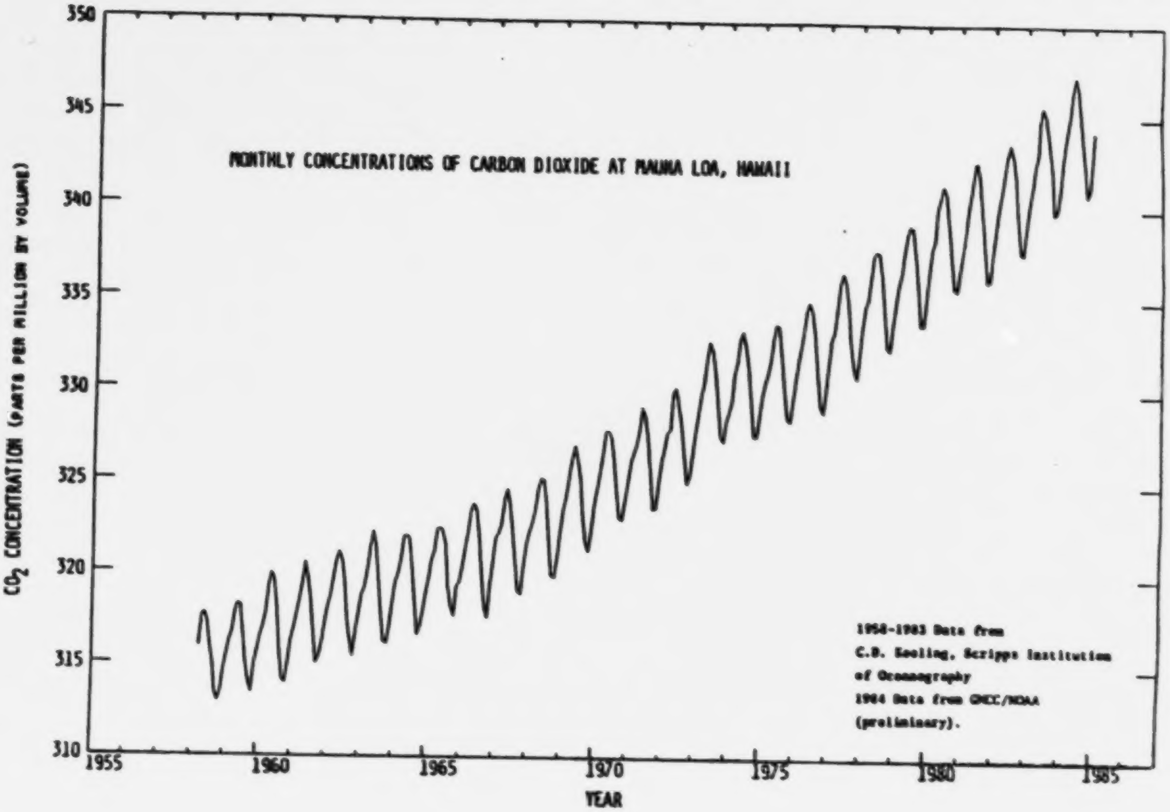


Figure 1. Measured increases in tropospheric carbon dioxide (CO_2) concentrations.

Monthly measurements from Mauna Loa, Hawaii. Data collection began in 1958 with the International Geophysical Year. Since that time, concentrations have increased 10 percent. Source: Keeling, C.D., and GMCC/NOAA, unpublished.

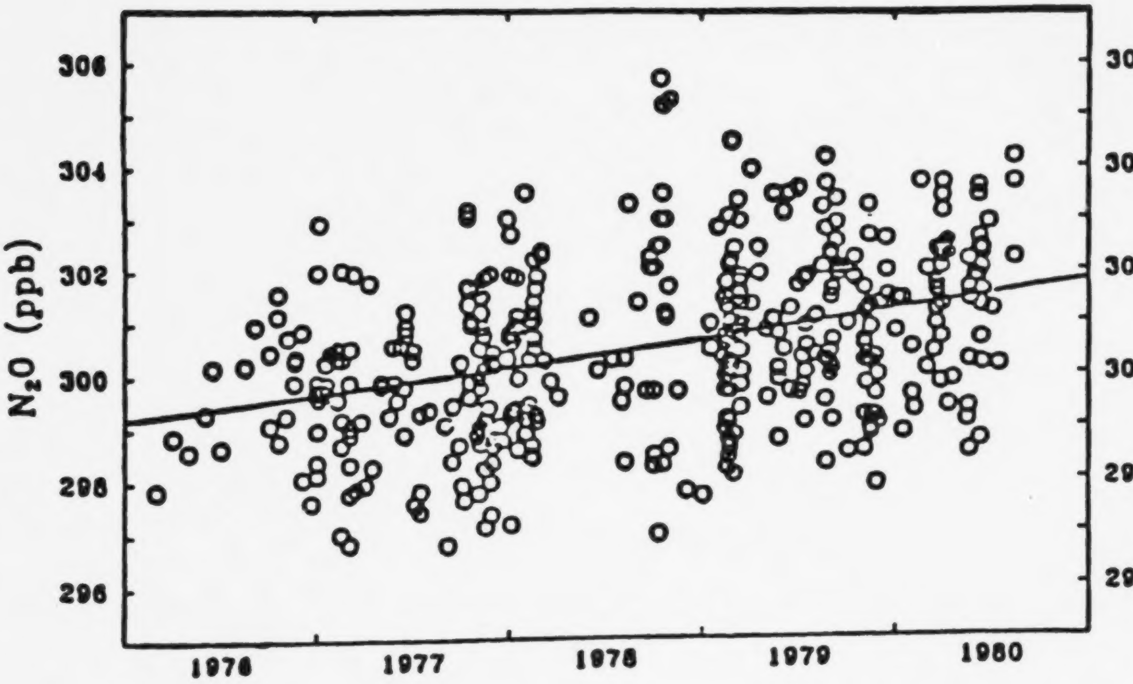


Figure 2. Measured increases in tropospheric concentrations of nitrous oxide (N_2O).

Data were collected at several monitoring sites and aboard vessels in the major world oceans. Concentrations increased at approximately 0.2 percent per year. Source: Weiss, R.F. The temporal and spatial distribution of tropospheric nitrous oxide. Journal of Geophysical Research. 86(C8): 7185-7195, 1981.

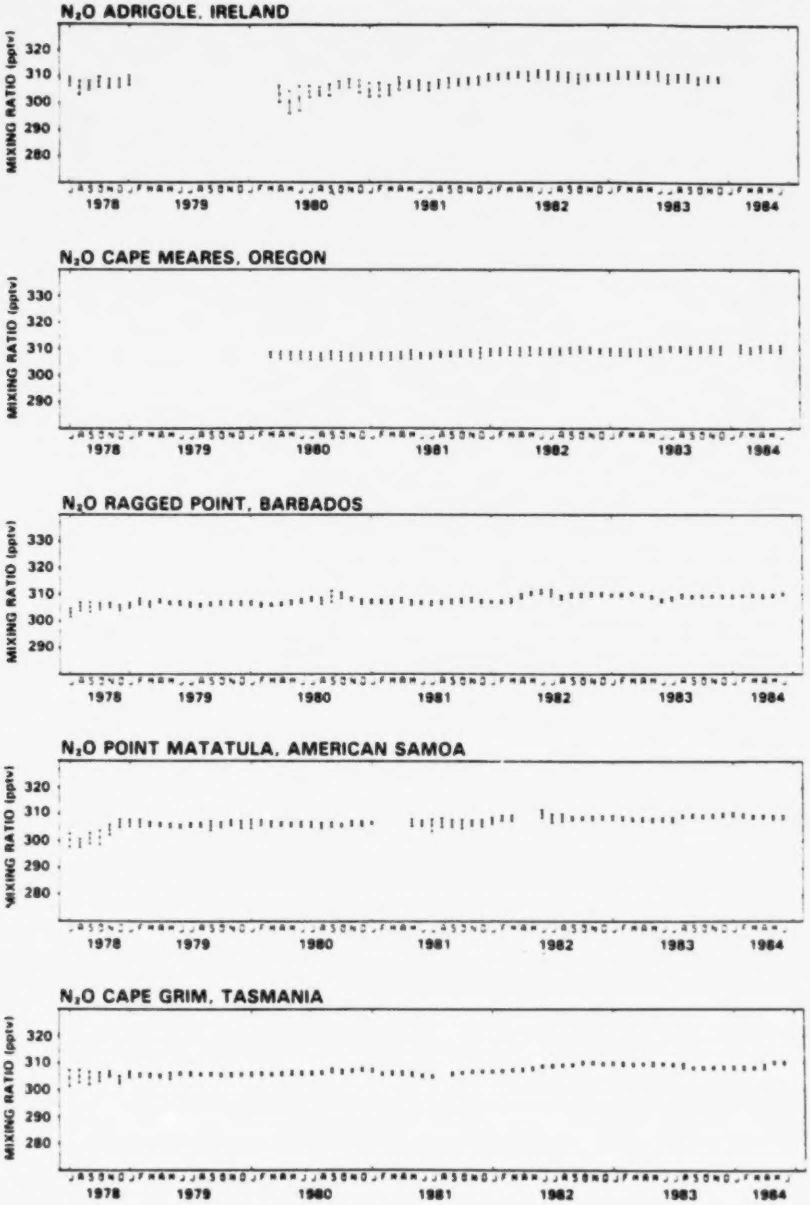


Figure 3. Measured increases in tropospheric concentrations of nitrous oxide (N_2O).

Annual rates of increase at the five monitoring stations above were: 0.77 percent, 0.27 percent, 0.24 percent, 0.09 percent, and 0.18 percent. While the rates of increase appear to be larger in the Northern hemisphere than in the Southern Hemisphere, there is little variation in actual concentrations. Data are from the Atmospheric Lifetime Experiment. Source: World Meteorological Organization. Atmospheric Ozone 1985: Assessment of our understanding of the processes controlling its present distribution and change. World Meteorological Organization, Geneva, Switzerland, 1986.

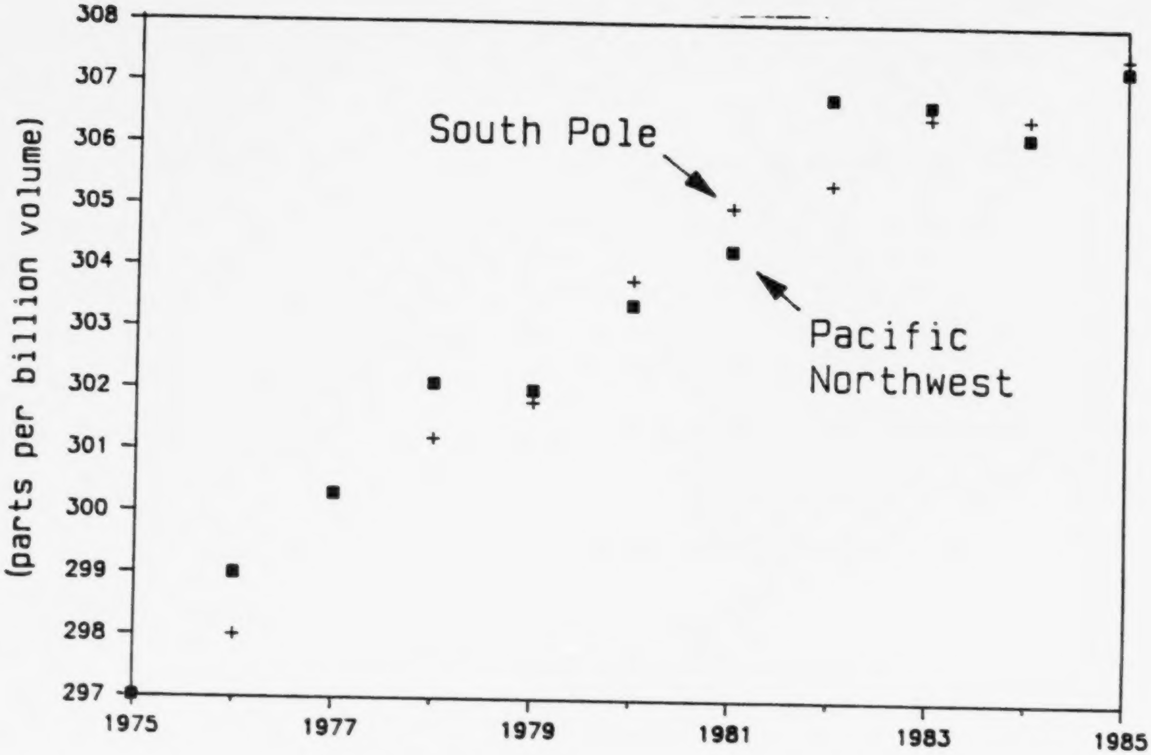


Figure 4. Measured increases in tropospheric concentrations of nitrous oxide (N_2O).

Data were taken at the South Pole and in the U.S. Pacific Northwest. Concentrations are increasing at about 0.3 percent per year. Source: Rasmussen, R.A., and M.A.K. Khalil. Atmospheric trace gases: trends and distributions over the last decade. Science. 232: 1623-1624, 1986.

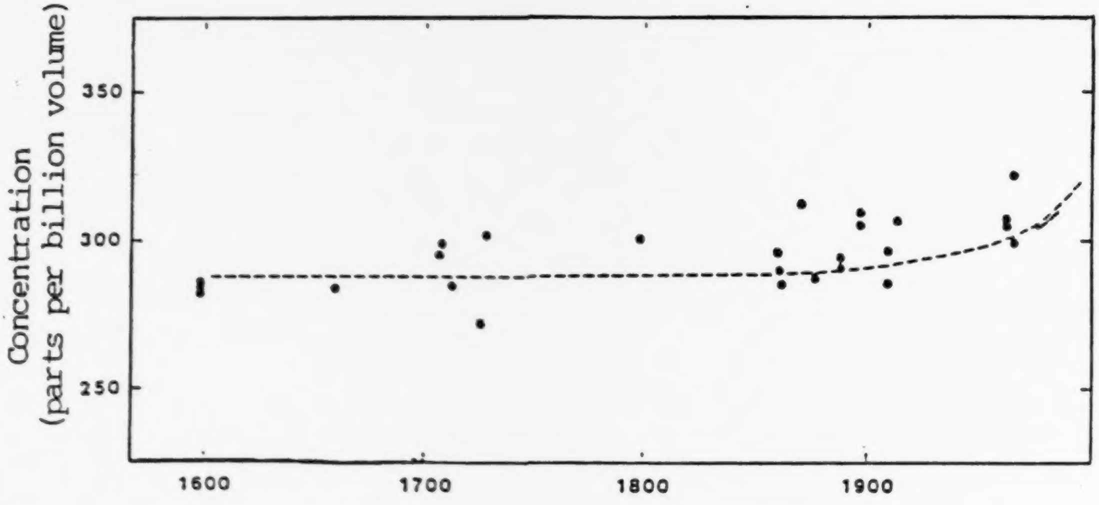


Figure 5. Ice core measurements of historical nitrous oxide (N_2O) concentrations.

The ice core data show that concentrations were relatively constant until the time of the Industrial Revolution. Since the year 1600 they have increased by 8 percent. Source: Pearman, G.I., et al. Evidence of changing concentrations of atmospheric CO_2, N_2O and CH_4 from air bubbles in Antarctic ice. Nature. 320: 248-250, 1986.

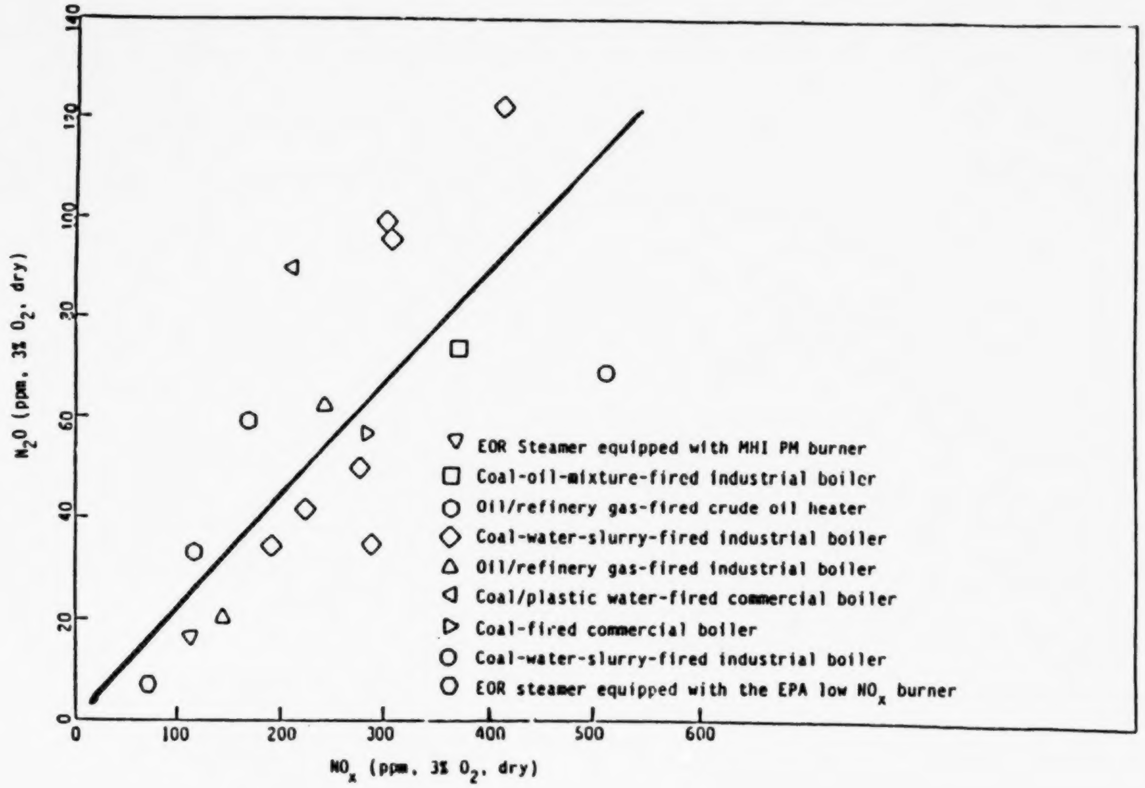


Figure 6. Nitrous oxide (N_2O) emissions versus NO_x emissions in combustion.

The data show that N_2O emissions from combustion are roughly proportional to NO_x emissions. Source: U.S. Environmental Protection Agency, Environmental assessment of an enhanced oil recovery steam generator equipped with a low-NO_x burner. Volume 1. Technical results. EPA Report No. 600/7-86-003a. 1986.

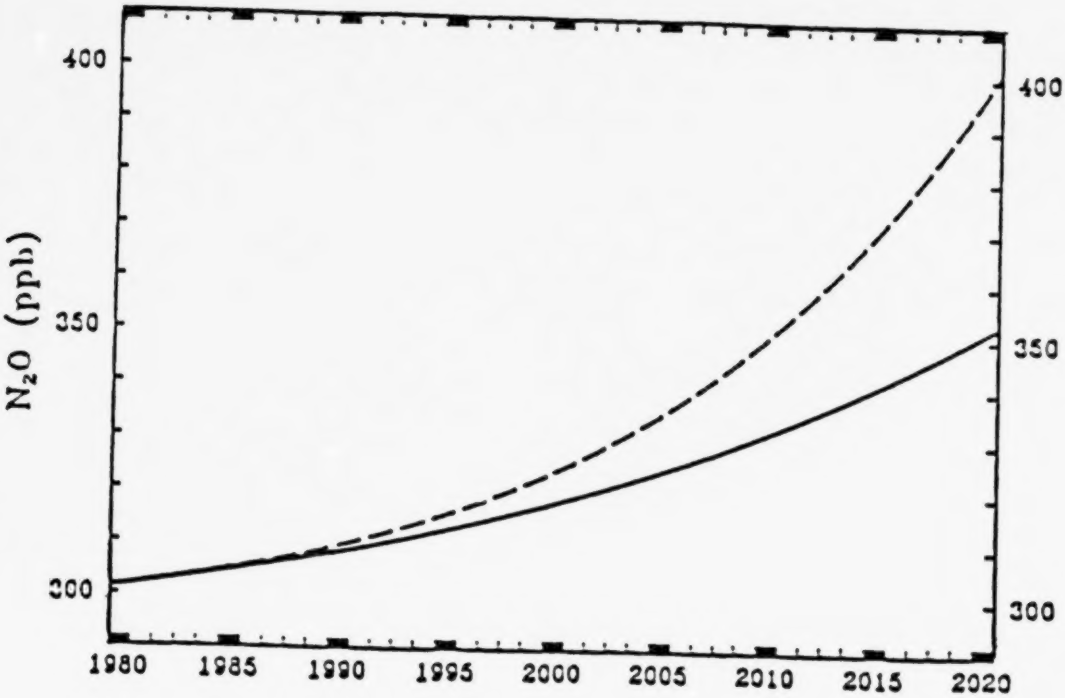


Figure 7. Projected increases in nitrous oxide (N_2O) concentrations, projected to the year 2020 with Weiss' emissions-concentrations model.

The upper dashed line represents total emissions growing at 6 percent per year; the lower solid line at 3.5 percent per year. Source: Weiss, R.F. The temporal and spatial distribution of tropospheric nitrous oxide. Journal of Geophysical Research. 86(C8): 7185-7195, 1981.

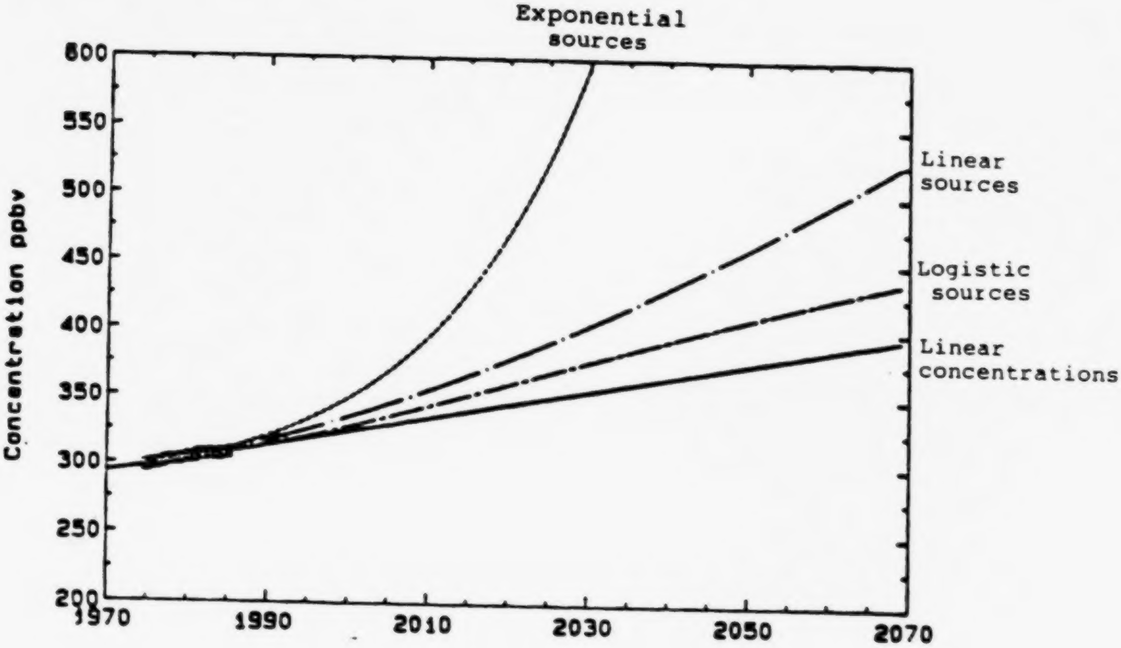


Figure 8. Projected increases in nitrous oxide (N_2O).

"Projections are based on various models for extrapolating present concentrations and emissions. The methods considered are a linear extrapolation of present rates of growth of concentrations, linear and exponential increases of present anthropogenic emissions, and a logistic model for the growth of emissions." Source: Khalil, M.A.K., and R.A. Rasmussen. Logistic and other models for the trends of nitrous oxide. In: National Oceanic and Atmospheric Administration. Geophysical Monitoring for Climatic Change. 1985 Annual Report. Volume 12, 1986.

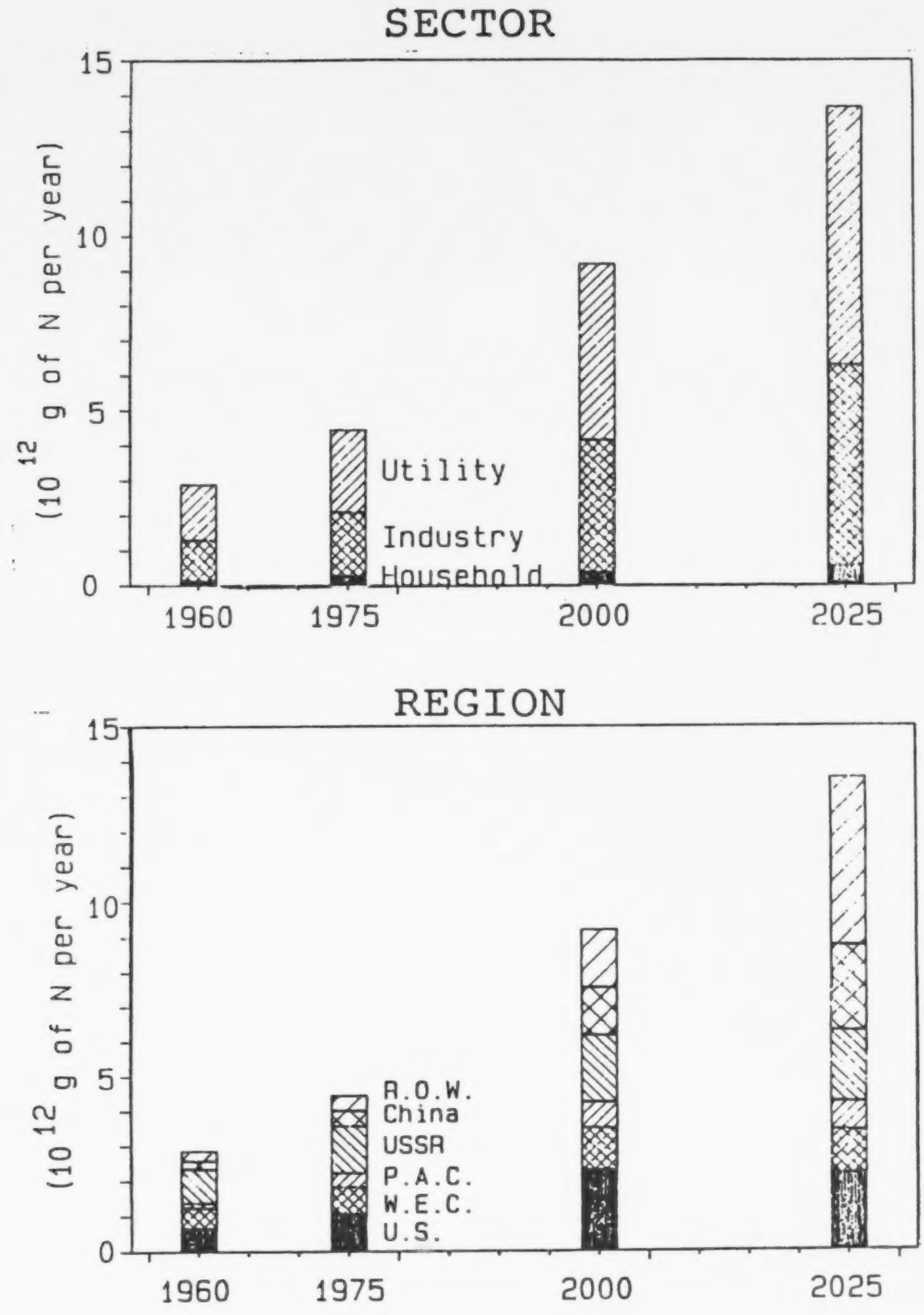


Figure 9. Historical and projected nitrous oxide (N_2O) emissions from combustion by sector and region.

Increases in N_2O are large: a doubling in emissions from 1975 to 2000 and a 44 percent increase from 2000 to 2025. Source: Source: Kavanaugh, M. Estimates of future CO, N_2O and NO_x emissions from energy combustion. Atmospheric Environment. 21(3): 463-468, 1987.

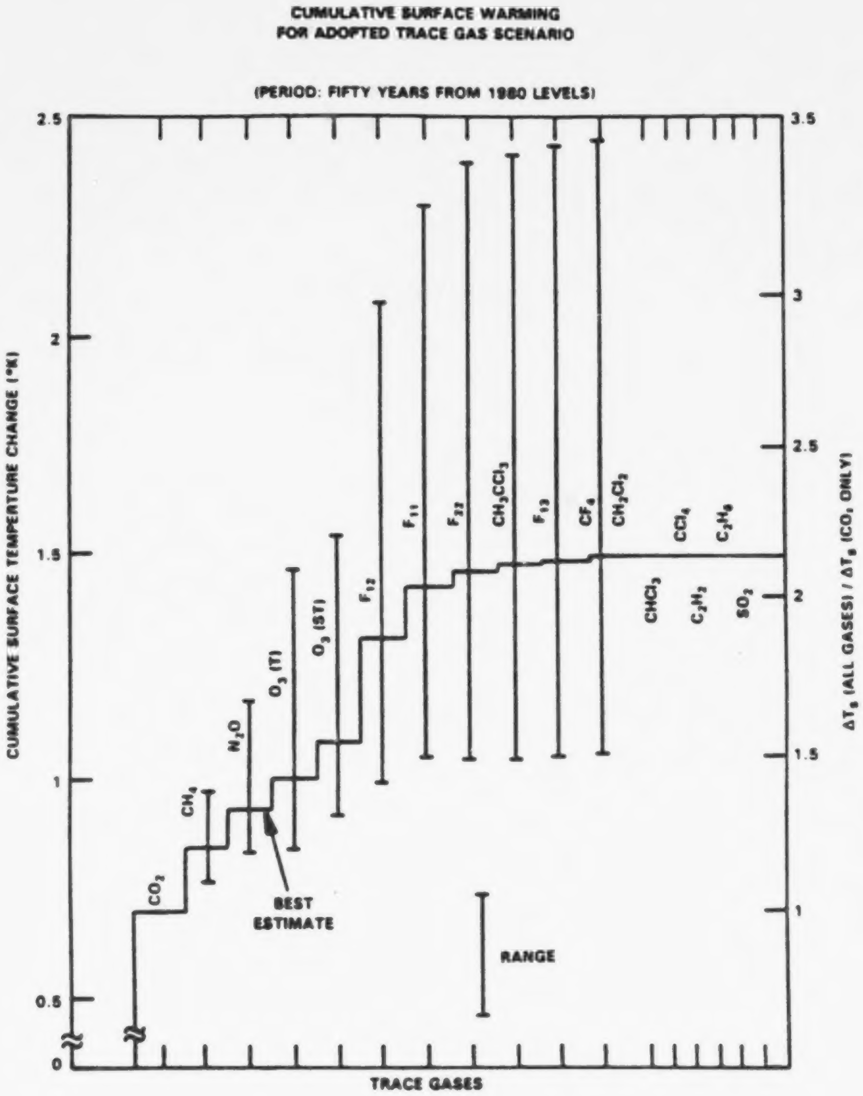


Figure 10. Projected equilibrium global warming for the year 2030 for central scenario of trace gas concentrations.

Note that other trace gases contribute twice as much to the warming as CO_2. Model estimates are for a sensitivity of 2 degrees Centigrade for doubled CO_2 concentrations. Source: Ramanathan, V. et al. Trace gas trends and their potential role in climate change. Journal of Geophysical Research 90(D3): 5547-5566, 1985.

TABLE 1. ATMOSPHERIC LIFETIMES OF TRACE GASES

Compound	Formula	Lifetime (years)
CFC-11	$CClF_3$	75*
CFC-12	CCl_2F_2	111*
CFC-22	$CHClF_2$	20#
CFC-113	$C_2Cl_3F_3$	90#
Carbon tetrachloride	CCl_4	50*
Methyl chloroform	CH_3CCl_3	6.5*
Halon 1211	CF_2ClBr	25#
Halon 1301	CF_3Br	110#
Methane	CH_4	11*
Nitrous oxide	N_2O	150*

* Source: World Meteorological Organization. Atmospheric Ozone 1985: Assessment of our understanding of the processes controlling its present distribution and change. World Meteorological Organization, Geneva, Switzerland, 1986.

# Source: National Academy of Sciences. Causes and effects of changes in stratospheric ozone. National Academy Press, Washington, D.C., 1984.

TABLE 2. GLOBAL SOURCES AND SINKS OF NITROUS OXIDE (N_2O)

ATMOSPHERIC BURDEN (10^6 tons as N)	1500
SINKS + ACCUMULATION (10^6 tons N per year)	14.0 +- 3.5
1. stratospheric photolysis + reaction with $O(^1D)$	10.5 +- 3
2. accumulation (0.7 ppb per year)	3.5 +- 0.5
SOURCES (10^6 tons N per year)	
1. Natural	9.7
Tropical soil emissions	7.4 +- 4
Non-tropical soil emissions	0.1 - 0.5
Oceans	2 +- 1
2. Anthropogenic	5.5
Combustion	
Utility coal and oil	2.12
Industry coal and oil	1.64
Households coal and oil	0.24
Tropical biomass	0.6
Non-tropical biomass	0.1
Fertilized agricultural lands	0.8

Source: Table is adapted from McElroy and Wofsy, as reported in World Meteorological Organization. Atmospheric Ozone 1985: Assessment of our understanding of the processes controlling its present distribution and change. World Meteorological Organization, Geneva, Switzerland, 1986. Combustion emissions are computed based on 1975 source estimates presented in Kavanaugh, M. Estimates of future CO, N_2O and NO_x emissions from energy combustion. Atmospheric Environment. 21(3): 463-468, 1987.

TABLE 3. SELECTED NITROUS OXIDE (N_2O) EMISSION FLUXES FROM UNDISTURBED SOILS

Mean Flux (10^9 cm^{-2} per sec)	Location	Environment	Duration	Reported by
0.45, 1.0	New Hampshire	Northern Hardwood Forest	1 year	Keller Goreau
5.7	Colorado	Natural Shortgrass Prairie	62 days	Mosier
17	Brazil	Tropical Moist Forest	8 months	Keller Goreau Demello
25	Puerto Rico	Subtropical Moist Forest	1 day	Keller

Source: Adapted from table prepared by M. Keller, as reported in World Meteorological Organization. Atmospheric Ozone 1985: Assessment of our understanding of the processes controlling its present distribution and change. World Meteorological Organization, Geneva, Switzerland, 1986.

TABLE 4. EMISSION COEFFICIENTS FOR NITROUS OXIDE (N_2O) AND NO_x FROM COMBUSTION

(g of N per 10^9 J)

	Coal	Oil	Gas	Wood
UTILITIES				
N_2O	54.76	30.12	5.48	n.a.
NO_x	120.52	66.81	58.95	n.a.
INDUSTRY				
N_2O	46.55	21.90	2.74	0.82
NO_x	100.83	52.38	18.33	6.50
HOUSEHOLDS				
N_2O	8.21	8.21	2.74	0.82
NO_x	15.72	17.03	13.10	6.50

Source: Kavanaugh, M. Estimates of future CO, N_2O and NO_x emissions from energy combustion. Atmospheric Environment. 21(3): 463-468, 1987.

TABLE 5. EFFECTS OF CHANGES IN ATMOSPHERIC COMPOSITION

COMPOUND	STRATOSPHERIC OZONE	GLOBAL TEMPERATURE
Chlorofluorocarbons	Depletes	Increases
Halons (Bromine)	Depletes	Increases
Methane (CH_4)	Counters depletion: Adds ozone in the troposphere	Increases
Carbon Dioxide	Adds ozone	Increases
Nitrous Oxide (N_2O)	In high chlorine cases, counters depletion By itself, depletes	Increases

Source: U.S. Environmental Protection Agency. An assessment of the risks of stratospheric modification. Draft report. U.S. EPA, Washington, D.C., 1987.

OVERVIEW OF RECENT DEVELOPMENTS IN NO_x CONTROL IN EUROPE

by

Prof.Dr. O. Rentz
Dipl.-Ing. R. Leibfritz
Institute for Industrial Production
University of Karlsruhe
Hertzstraße 16
7500 Karlsruhe 21
Federal Republic of Germany

ABSTRACT

Based on the emission control legislation in some European countries recent developments are presented leading to the current status of NO_x abatement technologies and their application to stationary sources (power plants and industrial processes).

The state of $DeNO_x$ implementation in Europe in the field of primary and secondary NO_x emission control is outlined. This including informations on initial status at both full-scale and pilot plants, available and applied control technologies, transfer problems with regard to site specific conditions, advanced problem solutions and state of commissioning.

The future application of $DeNO_x$ technologies at industrial processes is briefly outlined.

Investment and cost figures are discussed.

1 INITIAL EMISSION SITUATION AND LEGAL EMISSION CONTROL REQUIREMENTS IN EUROPE

For a long time air pollution control measures for stationary sources introduced in Europe were aimed mainly at the control of SO_2 emissions. However, since the early 1980s nitrogen oxides (NO_x) have also been brought into close causal relation with damage observed in ecological systems.

To start an effective NO_x control strategy, it is necessary to know about the relevant emission sources. **Table 1** includes current data on the total annual NO_x emissions and the percentages of the various emission sources in some European countries. However, comparing the absolute values it has to be taken into account that the data basis may differ in the countries. The values indicate that NO_x emissions result to approx. 40 % from the energy supply and industrial sector.

NO_x emission control measures in one single country are not very effective with regard to improved ambient air quality because the latter depends also on the long-range transboundary transport and atmospheric conversion processes. **Figure 1** shows the European countries, in which NO_x control legislation for stationary sources is already enforced or drafts are under discussion. This means in particular Federal Republic of Germany (FRG), Austria, Switzerland, Netherlands, Denmark and Sweden (8,9). Moreover, the European Community proposed a directive in 1983 (amended 1985) aiming at a long-range NO_x control for new firing installations in the member countries. The directive has not yet passed.

Table 2 summarizes actual NO_x emission standards or guidelines respectively for new coal-fired boilers in the highest capacity range in several countries (8,9,10). A detailed compilation of NO_x emission standards in Europe is enclosed in Appendix 1.
The most stringent and comprehensive emission requirements for stationary sources are currently in force in the FRG both for new and existing units. For new units in Austria a draft of the so-called "Dampfkesselemissionsgesetz (boiler emission law)" aims at a NO_x emission standard of 150 mg/m³ (standard conditions).

Figure 2 illustrates the development of the emission standards for big utility boilers (700 MW) in the FRG compared with those in Japan (on the basis of the national emission standards) and in the USA.
In June 1983, the Statutory Ordinance for Large Furnaces (GFAVO) was passed in the FRG covering both new and existing firing installations with a thermal heat input of more than 50 MW (in the case of gas firings 100 MW). In view of the rapid development of NO_x emission control technique, the Ordinance specified emission standards achievable with combustion modification. In addition, a general requirement to apply the best available control technique (so-called "Dynamisierungsklausel") was integrated in the Ordinance. The Council of the Federal and State Environment Ministers tightened these general requirements in 1984 to the standards shown in Table 2 necessitating the implementation of NO_x flue gas cleaning systems at boilers of more than 300 MW. The standards for plants below 300 MW can be met by combustion modifications. Also

existing plants (where the expected and declared operation time is more than 30,000 h) have to comply with the standards by 01.07.1988 for dry bottom boilers and by 01.07.1990 for wet bottom boilers.

However, it has to be taken into account that the NO_x emission standards in the GFAVO represent a recommendation to the enforcing authorities. In the individual case they may define even lower NO_x emission values to power plants; e.g. in Munich 100 mg/m³ (coal-fired) and in Hannover 150 mg/m³ (coal-fired).

The revised "Technical Instruction for Air Pollution Control (TA Luft)" passed in March 1986, covers smaller firing installations with a thermal heat input of less than 50 MW (in the case of gas firing 100 MW) and high temperature industrial processes. In **Table 3** (11) some emission standards for industrial processes are listed as an example. Emission requirements apply to both new and existing units: for the latter the time limit for compliance is 1989, 1991 or 1994 depending on the actual plant emission.
Due to further operational experiences with $DeNO_x$ technologies in firing installations, lower NO_x emission standards could be introduced in the TA Luft without adding general requirements. For most of the industrial processes flue gas denitrification is not yet commercially available: in this case general requirements have been defined in the TA Luft. But it can be stated, that many such processes will have to be equipped with $DeNO_x$ systems in the near future (12).

When comparing emission standards it must be done in relation to the measurement and evaluation method of emission values. **Figure 3** shows the compliance requirements for NO_x emissions (13,14). NO_x emissions must be continuously measured and calculated as half hour mean values. For the annual operation an emission standard is met if

- 100 % of all daily mean values are equal or less emission standards
- 97 % of all half hour mean values are equal or less 1,2·es
- 100 % of all half hour mean values are equal or less 2·es

This is for firing installations covered by the GFAVO and TA Luft.

2 TECHNOLOGIES FOR NO_x REMOVAL AND APPLICATION STATUS IN SOME EUROPEAN COUNTRIES

2.1 FEDERAL REPUBLIC OF GERMANY

2.1.1 Primary Measures

Primary measures aim at avoiding NO_x during the combustion of fossil fuels. For this purpose the following possibilities are given in general:

- shut down of old boilers emitting a high amount of NO_x and

start up of new, low NO_x emitting boilers,
- fuel change. Seems to be restricted with regard to the energy supply security and longterm-policy of several countries (e.g. the so-called century contract for coal in FRG),
- combustion modifications.

To achieve maximum success in NO_x reduction with combustion modifications the different NO_x formation mechanism must be taken into account as well as the main NO_x formation parameters i.e.

- combustion temperature
- O_2 content in the combustion zone
- residence time of nitrogen in high temperature zone
- N-content of fuel

which influence NO_x formation in a complex mechanism depending on the fuel.

Figure 4 summarizes effective measures for combustion modifications. These are especially

- optimized boiler design (low volumetric heat release, low combustion temperature)
- flue gas recirculation
- low NO_x burner (air-fuel staging at single burner)
- air-fuel-staging in the combustion chamber

which are partly already tested or in operation.

These measures may be applied individually to new plants as well as in purposeful combination: on the other hand applicability to existing plants depends on site specific conditions. The different conceptions for combustion modifications have to be distinguished according to the fuel and firing system.

Optimizing the boiler design is highly site specific and as a rule only effective for new plants. Low NO_x burners are well developed especially for boiler installations and a good number of burner systems are available for coal-, oil- and gas-fired boilers. Off-stoichiometric-combustion/overfire air is applicable to new and retrofit systems of all boiler types; in the latter case depending on design. Flue gas recirculation, especially appropriate for oil and gas-fired plants as well as for high temperature combustion, e.g. wet bottom boilers, is also well proven for new and retrofit installations (3).

Figure 5 (15) shows the proposal of the VGB for a promising procedure in retrofitting boilers with combustion modifications. The NO_x reduction degree is mentioned qualitively. It must be remembered, however, that the total reduction effect is lower than the sum of the individual effects. Even the reduction effect of one single measure can differ when applied to a similiar boiler type.

In a further step a significant improvement of NO_x control is expected from fuel-staging-burner-systems or fuel-staging in the furnace (IFNR, Reburning, MACT) respectively. First tests have been successfully carried out in the FRG. **Figure 6** (16) shows emission values of a fuel staged 15 MW burner. Under the given test conditions and the coal types NO_x emission values of less than 400 mg/m³ could be achieved. In the same time unburnt carbon and CO increased. Current research and development work is necessary.

The emission values summarized in **Table 4** (3) have been demonstrated for retrofitting low NO_x combustion systems in existing utility boilers.

In general the extent to which combustion modifications can be used is limited by the following operational side-conditions; especially for retrofit systems:

- flame stability
- enhanced corrosion and erosion
- ash melting behavior (wet bottom boilers)
- burn-out (more than 5 % unburnt carbon in fly ash)
- heat surface slagging
- water/steam circle.

The technical realization of the existing plant regulation in the GFAVO is currently going on in the FRG. A large number of existing power plants is being retrofitted with combustion modifications. In the case of dry bottom hard coal firings mainly low-NO_x burner systems and overfire air are applied (17). For wet bottom hard coal firing overfire air, flue gas recirculation and low-NO_x burners are applied (17,18). As a characteristic of this process, lignite firing systems already achieve lower NO_x emissions (flue gas recirculation to dry the fuel, lower combustion temperature, tangential firing systems) (18). Thus for further NO_x reduction the effect of overfire air is being investigated.

Concerning the reduction degree of primary measures in the ideal case it has become obvious that these measures alone are insufficient to achieve the envisaged German emission limit of 200 mg/m^3 in the foreseeable future. Therefore secondary measures (flue gas cleaning systems) must be applied.

2.1.2 Secondary Measures (Flue Gas Cleaning)

A great variety of processes for NO_x flue gas cleaning have been developed especially in Japan, USA and FRG, but only a few processes are already available for full-scale application. Due to the short period for retrofitting existing power plants with $DeNO_x$-systems (approx. 4 to 6 years), the technical development stage of the processes was a decisive factor for process selection in the FRG.

Therefore mainly the following processes are or will be applied to utility boilers (19):

- SCR-process (more than 90 % market share)
- SNCR-process
- activated carbon process of Bergbauforschung/Uhde (BF/Uhde)
- Fe-EDTA-process of Saarberg-Hölter-Lurgi (SHL).

The latter two are simultanous SO_2/NO_x removal processes.
Japanese SCR-technology is well proven in Japan. Most suppliers of $DeNO_x$-systems in the FRG have taken Japanese licences. Although considerable experience of large scale technical operation has become available, mainly from Japan, the significant differences between Japan and the FRG, mentioned in **Table 5**, in operating coal fired power plants have to be taken into account when transferring SCR-technology:

- load factor: in Japan mainly base load operation; in the FRG middle load operation needing daily starts and stops
- fuel variety: in Japan mostly high quality hard coal; in the FRG a wide coal spectrum from lignite to various kinds of domestic hard coal
- firing system: in Japan only dry bottom boilers; in the FRG also wet bottom boilers.

The further development and testing of the SCR-process as well as of other $DeNO_x$-processes (e.g. EBDS, Walther) is currently being practised in a series of $DeNO_x$ demonstration and pilot plants in the FRG (19). Regarding the SCR-Process emphasise is put on catalyst performance in high-dust systems in hard coal-fired wet bottom boilers, in lignite-fired boilers and at boiler load changes.

Figure 7 (20) outlines the implementation status of $DeNO_x$ systems in coal-fired utility boilers and shows the main suppliers of $DeNO_x$ equipment. For almost 1/5 th of the all installed electrical capacity orders have already been made, mainly to suppliers with a Japanese licence.

Figure 8 (20) shows the applied $DeNO_x$-processes and the equivalent capacity treated. The secondary measure implemented in most cases is the SCR technology; in the meantime five full scale SCR-plants are successfully in operation. All of them at hard coal-fired utility boilers, one being a wet bottom boiler.

The first SCR-plant in Europe started operation in Dec. 1985 at the 460 MW Altbach power station of the Neckarwerke AG; more detailed information on operating experience with this and other plants will be provided in the reports of Dr. Necker and Dr. Goldschmidt.

The first full-scale plant for simultaneous precipitation of SO_2 and NO_x according to the activated carbon process is scheduled for operation in the middle of 1987 at the lignite-fired Arzberg power station (237 MW). If this process can prove its full-scale applicability it may have, as a single $DeNO_x$ process, some advantages compared to other processes in case of tail-gas $DeNO_x$ system. Since the adsorption and reduction of the NO_x takes place at a temperature of 90 to 120 ^oC (the temperature range for selective catalytic reduction is around 320 to 400 ^oC), costly reheating of flue gas with additional burners is unnecessary.

Also in the middle of 1987, the first simultaneous removal plant using the SHL-process will start operation at the coal-fired Heyden power station (800 MW). In the SO_2 absorber the NO_x is absorbed in a Fe-EDTA solution and finally reduced.

A comprehensive overview on all power stations with $DeNO_x$ equippment is enclosed in Appendix 2.

2.2 Austria (3,10)

In Austria a great number of existing boilers mainly lignite fired, is currently being retrofitted with low NO_x combustion systems. Moreover flue gas cleaning, especially SCR-technology is planned for utility boilers. **Table 6** (10,21) includes a compilation of the $DeNO_x$ systems.
The retrofitted SCR-system (plate type catalyst, 80% $DeNO_x$ capacity) at the Dürnrohr power station operates sucessfully since October 1986. Start up of the $DeNO_x$ system at Mellach power station is expected for end of 1987. The performance of different catalyst types is investigated at a lignite fired pilot plant at Voitsberg power station.
Recently order was made to SGP-MHI to install a SCR-System at the Lopoldau gasturbine.

2.3 Netherlands (3)

In the Netherlands a feasability study is currently in progress to evaluate different combustion modifications.
The availability of the SCR-process will be proved under the specific Dutch conditions of rapidly changing coal quality and load fluctuations at a demonstration unit of 60 MW.

2.4 Sweden (22)

In the last year a growing interest for R&D on reburning technologies for NO_x control was experienced. There are some preliminary results that show a very promising reburning effect by using peat and especially wood as a reburning fuel.

Concern to flue gas denitrification is concentrated on SCR technologies. Interesting developments are a cheap low temperature catalyst with high activity down to less than 100 °C and an SCR-system based on dispersion of the catalyst in the flue gas followed by a baghouse or electric precipitator.

2.5 Others

In France and Great Britain the installation of low-NO_x burners is prefered. Further NO_x reduction with flue gas cleaning systems is currently not planned.

3 NO_x CONTROL MEASURES IN THE INDUSTRIAL SECTOR

The Federal Environment Agency estimates (1982) that approx. 50.000 plants are covered by the TA Luft. 15.500 of these plants are firing installations, the others being in industrial production. An overview is given in **Table 7** (23). More than 75 % of the plants are fired with oil or gas. Firing systems used for solid fuels are grate firings (96%), coal dust (3,5 %) and fluidized bed combustion (0,5 %). The firing installations consist of approx. 34,000 steam boilers. **Figure 9** (20) shows the percentage of the different fuels used in this industrial boilers. Thus the potential of emission reduction may be roughly estimated.
The total NO_x emission of these plants is 140,000 t NO_2/a (estimated for 1982), corresponding to about 5 % of the total NO_x emission in the FRG.

Depending on design, fuel and operation conditions of the boilers the NO_x base emissions of these plants varies between 100 to 800 mg/m³ (24).

Concerning solid fuels the emission standards may be met with combustion modifications; e.g. base emission of grate firings is around 200 to 600 mg/m³ (24).

With an optimized burner/furnace-design, the NO_x emission standard may be met at firing installations burning light distillate oil or crude oil. In the retrofit case application of low NO_x combustion techniques may be limited by increasing soot content.
With regard to gaseous fuels the emission standard as a rule can be achieved at new plants by means of combustion modifications like flue gas recirculation or air staging (24). Applicability have also been proven for retrofit installation. If in the individual case primary measures are not sufficient to meet emission regulations catalytic or non-catalytic denitrification processes are available (24).

In some cases low-NO_x burner systems are applied in industrial combustion processes; e.g. furnaces in refineries, in the iron and steel industry and in the cement industry. There, special precalcination processes had been developed in Japan achieving NO_x emissions of less than 400 mg/m³ (10 % O_2). Applicability of these processes is currently being investigated in some ECE countries. For space reasons retrofitting seems to be difficult.

4 INVESTMENT AND COSTS OF NO_x CONTROL TECHNOLOGIES

A total investment of around $7 \cdot 10^9$ DM (12) will be expected to equip the fossil fired power plants in FRG with $DeNO_x$ systems in order to meet the emission requirements of the GFAVO.

As for primary measures, the installation of low NO_x burners in new plants needs almost no additional costs. The retrofit case, however, is hard to estimate precisely, because in some cases considerable reconstruction may be necessary.
Table 7 (25) gives some estimates of the specific investment for primary measures in the FRG. The average specific investment is expected to be in the range of 40 DM/kW(t).

Installation of fuel-staging burner systems or fuel-staging in the combustion chamber requires higher expenditures.

Figure 10 (3) shows the investment for an SCR-unit at new power stations in the FRG in relation to the electric capacity. The cost figures include both requirements for construction and the catalyst. Thus, the specific investment is expected to be 100 to 150 DM/kW for coal-fired boilers and 50 to 100 DM/kW for oil- and gas-fired boilers. Other cost estimates regarding investment without catalyst (which may considered as variable costs) result in a specific investment of 55 to 100 DM/kW for coal fired boilers.

The different SCR-arrangements change the costs by about +/- 10 % (excluding catalyst costs).

The estimates of capital-related costs orientate themselves according to VDI-guideline 3800 as follows:

- depreciation (15 years) : 7,5 %/a
- interest on the average invested capital : 8 %/a
- maintenance, repair : 4 %/a
- taxes, insurance, etc. : 3 %/a

According to these assumptions the capital-related costs amount to a total of 18,5 %/a of the investment.

The operating costs mainly depend on catalyst life expectancy and operating hours.

Figure 11 (3) represents the specific emission control costs in DPf/kW (= 0,01 DM/kW) for coal-fired utility boilers.
The total specific costs for an SCR-unit at a 700 MW boiler under European conditions can be expected to be of

- 0,5 to 0,9 DPf/kW (dry bottom boiler)
- 0,6 to 1,2 DPf/kW (wet bottom boiler)

for a catalyst lifetime of 3 to 5 years.

With regard to NO_x removal and for economic reasons, in most cases firstly the potential of less costly combustion modifications is used to meet emission requirements and finally more costly flue gas cleaning systems, if stringent emission requirements exist.

REFERENCES

(1) Umweltbundesamt: Daten zur Umwelt 1986/87. Erich Schmid Verlag, Berlin, 1986

(2) Houllier, Ch., C.I.T.E.P.A., Paris: Personal communication, Febr. 1987

(3) ECE: Technologies for Controlling NO_x Emissions from Stationary Sources. Report of the NO_x Task Force, Karlsruhe, July 1986

(4) Allen, G., Industrial Air Pollution Inspectorate, London: Personal communication, Febr. 1987

(5) Österreichische Bundesregierung: Energiebericht 1986. Bundesministerium für Handel, Gewerbe und Industrie, Wien 1986

(6) van Ostveen, H., Ministerie van Volkshuisvesting, Ruimtelijke Ordening en Milieubeheer, Leidschendam: Personal communication, Febr. 1987

(7) Talleraas, P., Ministry of Environment, Oslo: Personal communication, March 1987

(8) Lange, M.: Vorschriften und Vollzug von Anforderungen zur NO_x-Emissionsbegrenzung bei Großfeuerungsanlagen in Europa. in Proceedings NO_x-Symposium Karlsruhe 1985, S. C1 bis C33

(9) Kolar, J.: NO_x-Grenzwerte und Emissionsminderungsmaßnahmen im internationalen Vergleich. Gas Wärme International 35 (1986) Nr.4, S. 227 bis 237

(10) Hackl, A.: Die Technik der Verminderung von Stickoxidemissionen. ÖIAZ 130 (1985) Nr. 10, S. 321 bis 334

(11) Davids, P., Oels, H.-J., Rosenbusch, K.: Technische Konsequenzen der NO_x-Emissionsgrenzwerte in der Bundesrepublik Deutschland. Gas Wärme International 35 (1986) Nr.4, S. 178 bis 186

(12) Davids, P.: Application of SO_2 and NO_x Control Technologies to Stationary Sources. Proceedings of Clean Air Congress, Sydney 1986, S. 470 bis 478

(13) Davids, P., Lange, M.: Die Großfeuerungsanlagenverordnung/Technischer Kommentar. VDI-Verlag, Düsseldorf, 1984

(14) Davids, P., Lange, M.: Die TA Luft/Technischer Kommentar. VDI-Verlag, Düsseldorf, 1986

(15) Autorenkollektiv: VGB-Handbuch: NO_x-Bildung und -Minderung bei Dampferzeugern für fossile Brennstoffe. Teil A: Problem NO_x, S. 15

(16) Rennert, K.D.: Möglichkeiten der Stickstoffoxidreduzierung in Feuerräumen. Fachreport Rauchgasreinigung. VDI-Verlag, Düsseldorf, Februar 1986

(17) Capitaine, D., EVT, Stuttgart: Personal communication, March 1987

(18) Schuster, H.: Feuerungstechnische Maßnahmen zur Minderung der NO$_x$-Emissionen aus Kraftwerken. Deutsch-Sowjetisches Symposium, Moskau, 9. bis 11.12.1986

(19) N.N: Stand der Stickoxidminderung durch Primärmaßnahmen. VGB Kraftwerkstechnik 66 (1986) Nr.8, S. 778 bis 781

(20) N.N.: Entstickung für fast 12000 Megawatt. Energie Spectrum Dezember 1986, S. 38 bis 43

(21) Konieczny, J, Institut für Verfahrenstechnik und Technologie der Brennstoffe (Prof. Hackl), Universität Wien: Personal communication, March 1987

(22) Ejner, B., National Environmental Protection Board, Solna: Personal communication, Febr. 1987

(23) Kier, B.: Abschätzung der Zahl und Struktur der betroffenen Anlagen. in VDI-Berichte 622, S. 17 bis 33. VDI-Verlag, Düsseldorf, 1986

(24) Davids, P.: Technische Umsetzung der TA Luft - Anforderungen bei Feuerungsanlagen. in VDI-Berichte 622, S. 1 bis 17. VDI- Verlag, Düsseldorf, 1986

(25) Bericht der Arbeitgruppe "Wirtschaftliche Entwicklung-Umwelt-Industrielle Produktion". Staatsministerium Baden-Württemberg, Stuttgart, Juni 1986

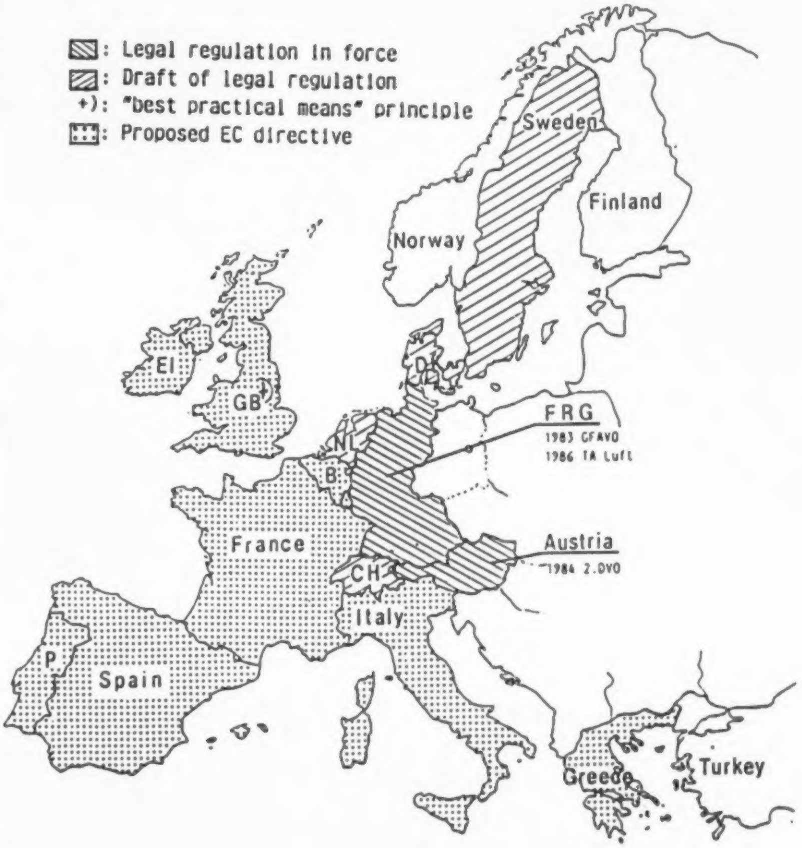
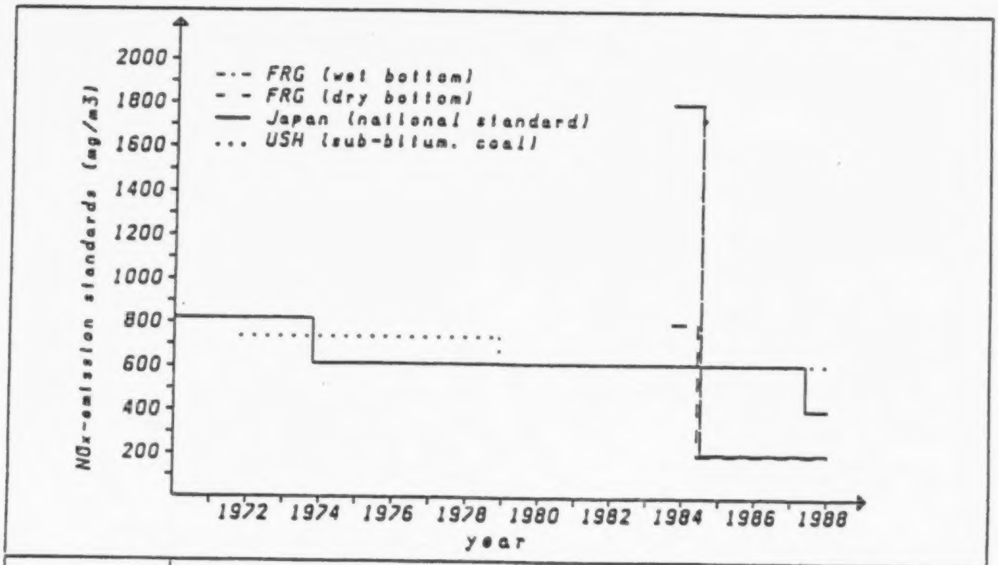

▧: Legal regulation in force
▨: Draft of legal regulation
+): "best practical means" principle
⠿: Proposed EC directive
Sweden
Finland
Norway
DK
EI
GB
NL
B
FRG
1983 GFAVO
1986 TA Luft
France
Austria
1984 2.DVO
CH
Italy
P
Spain
Greece
Turkey

Fig. 1: European countries applying legal regulations for NO_x-control at stationary sources.

UNI KA
IIP



UNI KA
IIP

Fig. 2: Development of NO_x emission standards for coal-fired utility boilers in FRG, Japan and USA

- 100 % of all daily mean values < emission standard (es)
- 97 % of all half hour mean values < 1,2 · es
- 100 % of all half hour mean values < 2 · es

Fig. 3: Compliance requirements for continously measured emission values in the FRG (GFAVO, TA Luft)

UNI KA
IIP

- optimized boiler design
- flue gas recirculation
- air/fuel staging at single burner (low NO_x-burner)
- air/fuel staging in the combustion chamber (overfire air; reburning)

Fig. 4: Main principal combustion modifications

UNI KA
IIP

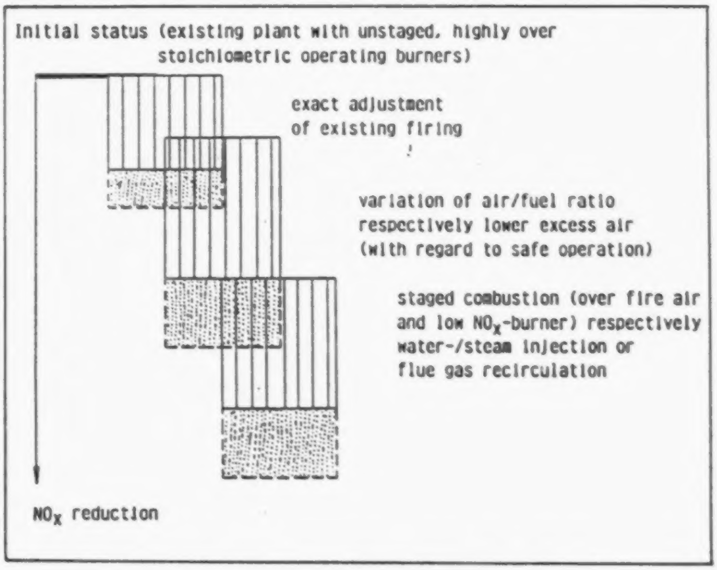

Initial status (existing plant with unstaged, highly over stoichiometric operating burners)
exact adjustment of existing firing
variation of air/fuel ratio respectively lower excess air (with regard to safe operation)
staged combustion (over fire air and low NO_x-burner) respectively water-/steam injection or flue gas recirculation
NO_x reduction

Fig. 5: Proceeding in applying combustion modifications to coal-fired boilers in the retrofit case

UNI KA
IIP

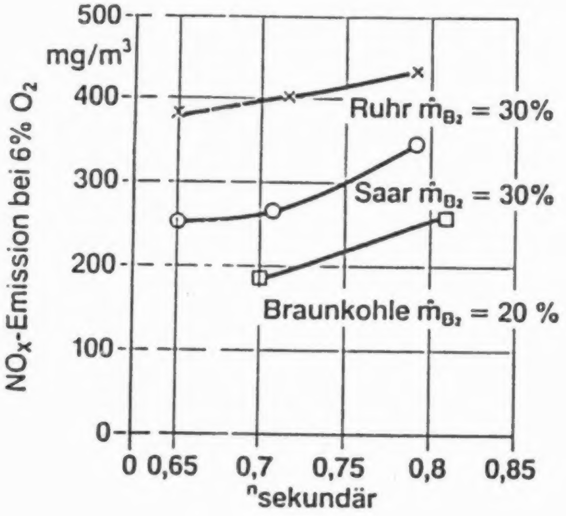


Fig. 6: Testresults with a fuel staged 15 MW burner using different coal qualities (NO$_x$ emission vs air ratio in secondary flame)
Ruhr, Saar: hard coal types
Braunkohle : lignite
$\dot{m}_B$ = portion of the reducing fuel

UNI KA
IIP

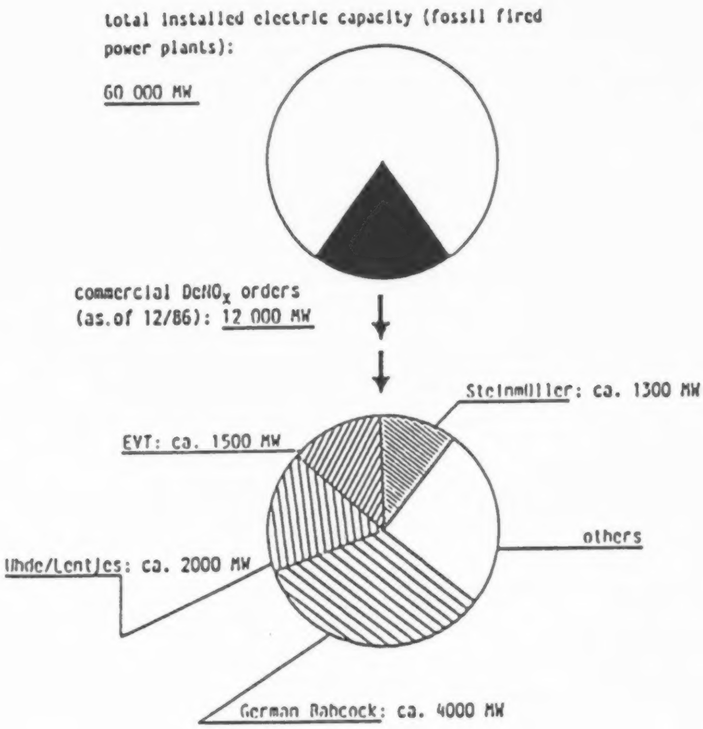
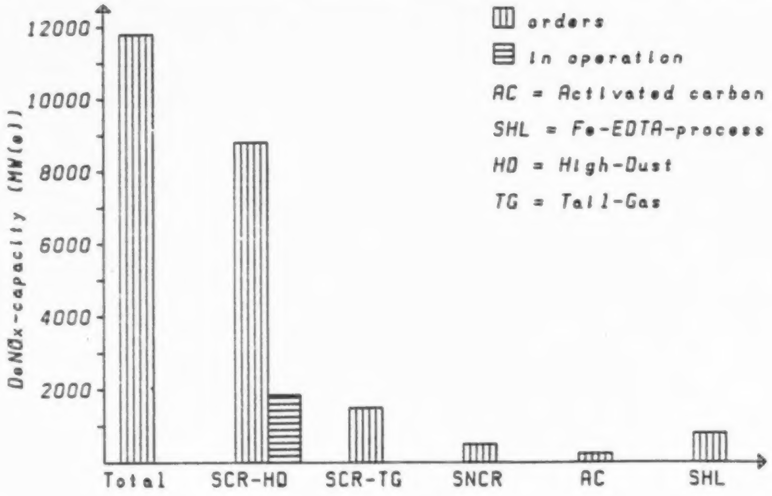


Fig. 7: Application status of DeNO$_x$ systems to stationary sources in FRG and main suppliers as of 12/86 (However, due to compliance datas (see chapter 1), the implementation status is booming.)

UNI KA
IIP



UNI KA
IIP

Fig. 8: Applied DeNO$_x$ processes to stationary sources in FRG (end 1986)

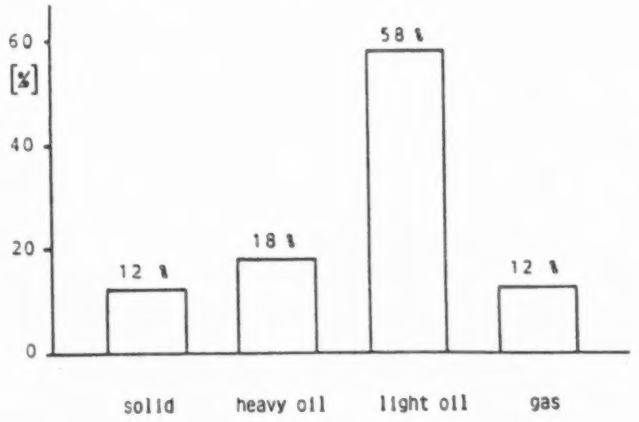
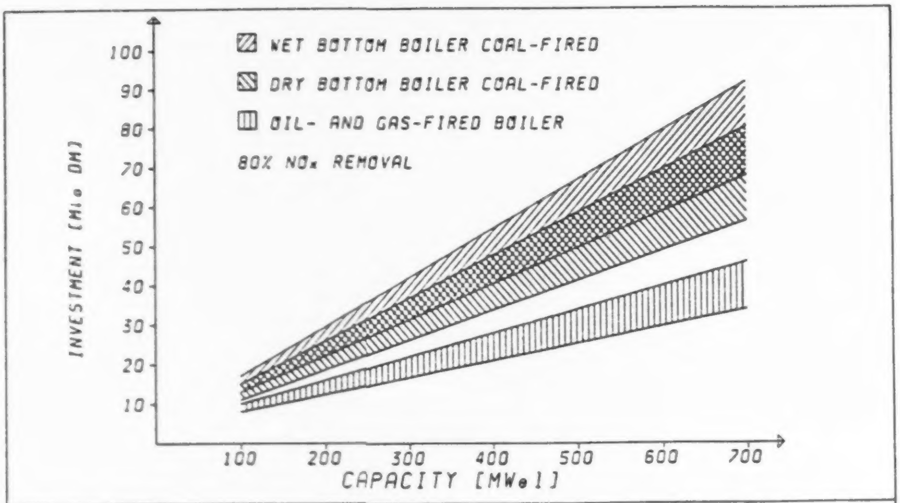


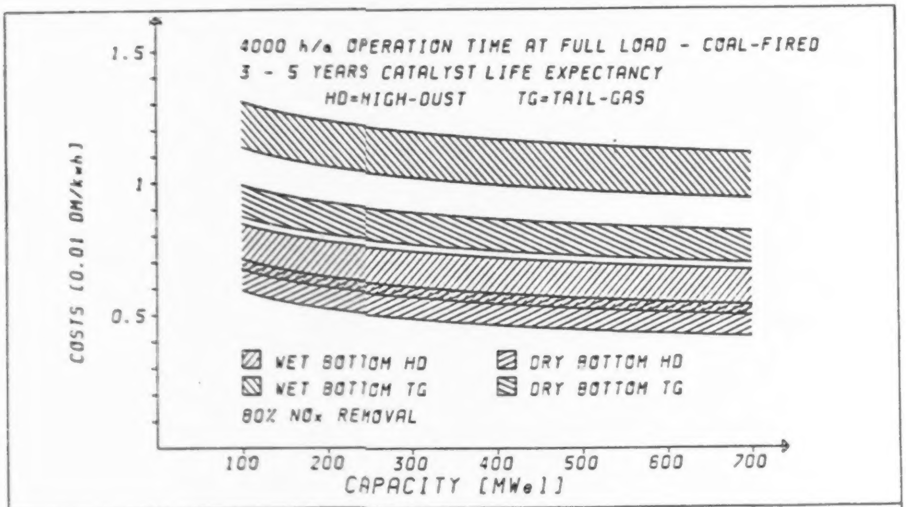
Fig. 9: Division of the industrial boilers (less than 50 MW; gas 100 MW) according to fuel in the FRG

UNI KA
IIP



UNI KA
IIP

Fig. 10: Investment for SCR units in the FRG at new utility boilers in relation to unit capacity



UNI KA
IIP

Fig. 11: Total additional costs of an SCR-unit at new coal-fired boiler in the FRG

Tab. 1 : Annual NO_x-emissions in some European countries and portion of emission sources

state	year	NO_x tot (10^6 t)	portion %			
			energy	industry	traffic	others
FRG /1/	1984	3,00	27,7 1)	10,7	57,3	4,3
France /2/	1986	1,63	7,4	12,3	70,1	10,2
Italy /3/	1980	1,48	--	--	--	--
Great Britain /4/	1984	1,69	37,0	12,2 4)	44,0	7,0
Austria /5/	1985	0,21	10,0	13,0	72,0	5,0
Denmark /3/	1982	0,25	51,0	14,0	34,0	1,0
Sweden /3/	1984	0,29	22,0 2)	6,0	72,0	--
Netherlands /6/	1985	0,50	25,5 1)	8,1 3)	56,8	9,6
Norway /7/	1984	0,14	8,0 1)	4,0	85,0	3,0

1) incl. industrial power plants
2) fuel combustion in general
3) portion of refineries 50 %
4) portion of refineries 2 %

UNI KA
IIP

Tab. 2: Compilation of NO_x-emission standards (as NO_2 in mg/m^3 at standard conditions) for new coal-fired boilers

country	capacity (MW(t))	NO_x-standard (mg/m^3 at 6% O_2)
Austria	>50 >300	800 150 (draft)
European Community (EC) (1983 proposed directive)	>50	800 (from 1.1.1985) (dry bottom) 1300 (from 1.1.1985) (wet bottom) 400 (from 1.1.1996) (dry bottom) 800 (from 1.1.1996) (wet bottom)
FRG	>300	200 (wet bottom) 200 (dry bottom)
Japan	>700*)	410+) (from Apr. 1987)
USA	>73	614 (sub-bituminous coal) 737 (lignite)

*): calculated as 1000 m^3/h = 1 MW(t)
+): national emission standard;
calculated as 1ppm NO_2 = 2,05 mg NO_2/m^3

UNI KA
IIP

Tab. 3: NO_x emission standards for thermal processes (TA Luft)

plant type	NO_x emission standards (mg/m^3)+)	general requirement*)	O_2 base %
internal combustion engine	diesel : 2000 to 4000 gasoline: 500 to 800	yes no	5
gasturbine	300 to 350	yes	15
coke oven	500	yes	5
cement works	1500 to 1800	yes	no
calcination furnace	1500 to 1800	yes	no
glass manufacturing	1200 to 1700	yes	8/13
melting furnace for mineral compounds	1400 to 2200	yes	8/13
sintering furnace	400	no	no
metal heating furnace	500 to 1300	yes	5
ic engine test facility	no	yes	no

+): at standard conditions
*): to apply best available control technology (Dynamisierungsklausel)

Tab. 4: Emission values for existing utility boilers with retrofitted low NO_x combustion systems

- pulverized coal firing (6 % O_2) :
  - wet bottom boiler : 1000 to 1400 mg/m^3
  - dry bottom boiler : 600 to 800 mg/m^3 (tangential)
600 to 1100 mg/m^3 (wall-fired)
- oil firing (3 % O_2) : 200 to 400 mg/m^3
- gas firing (3 % O_2) : 100 to 300 mg/m^3

Tab. 5: Differences in operating SCR-plants in Japan and FRG

	Japan	FRG
load factor	mainly base load operation	mainly middle load operation (daily start up and shut down)
fuel varity	few coal fired boilers (ca. 8600 MW); high quality coal	mostly coal fired boilers; coal property varies from high quality hard coal to lignite
firing system	dry bottom boilers	dry bottom boilers and wet bottom boilers

UNI KA
IIP

Table 6: Power plants equipped with flue gas $DeNO_x$-systems in Austria (10.21)

Unit	Status	Power (MW(e))	Fuel	Start-up
Dürnrohr	R	405 MW	hardcoal	autum 1986 (SCR-HD)
Dürnrohr	R	320 MW	hardcoal	autum 1986 (SCR-HD)
FHKW Mellach	U.C.	200 MW	hardcoal	end of 1987 (SCR-HD)
St. Andrä II	R	110 MW	lignite	autum 1986
Zeltweg	R	137 MW	hardcoal	autum 1987
Donaustadt, Block 3 and 4	R	380 MW	oil/gas	end of 1987 (SCR-HD)
Voitsberg III	P	330 MW	lignite	autum 1985 (SCR-HD)

R....retrofit
P....pilot unit (2 x 5000 m^3/h; plate and honeycomb type catalyst); final process decision expected in the middle of 1987)
U.C..under construction

UNI KA
IIP

Tab. 7: Number and capacity of existing firing installations with emission control requirements according to the TA Luft

fuel	number				total	capacity MW(t)
	capacity range MW(t)					
	1 to 5	5 to 10	10 to 50	50 to 100		
coal	3250	330	320		3900	20700
wood	1150	115	35		1300	4300
heavy oil	6800	1100			7900	27000
light oil		1200	600		1800	27000
gas			470	130	600	28000
total	11200	4170		130	15500	107000

UNI KA
IIP

Tab. 8: Estimates of the specific investment for combustion modifications in DM/kW(t)

combustion modification	
low NO_x burner (LNB):	8 to 16
overfire air (OFA):	16 to 24
flue gas recirculation (FGR):	24 to 32
LNB + OFA:	24 to 40
LNB + OFA + FGR:	40 to 64
average investment:	40

Appendix 1: Emission standards for NO_x (as NO_2 in mg/m^3 at standard condition) in Europe /8,9,10/

state	date	power P_t (MW)	status	fuel			remarks
				solid (6% O_2)	liquid (3% O_2)	gas (3% O_2)	
Belgium	--						
FRG	from 1.7.1984	> 300	new, old$^{1)}$	200	150	100	1) compliance deadline 1988 resp.1990 or decommissioning after less than 30000 h 2) Gas: 100 to 300 3) Gas: 10 to 100
		50 bis 300$^{2)}$	new	400	300	200	
			old	650	450	350	
	from 1.3.1986	1 bis 50$^{3)}$	new, old$^{5)}$	467 280$^{4)}$	450 HS/250 HL	200	
Denmark$^{8)}$	from 1984			1000$^{6),7)}$	500$^{6),7)}$		4) circulating or stationary FBC
France$^{9)}$	--						5) compliance dead-line 1989,1991 or 1994
Great Britain	--						6) only utility boilers
Netherlands	'til 1987	> 50	new	800$^{7)}$	450$^{7)}$	350$^{7)}$	7) no O_2-base 8) national bubble under discussion 9) NO_x tax under discussion
	from 1988	> 300	new	400$^{7)}$			
	(draft)	50 bis 300		500$^{7)}$	300$^{7)}$	200$^{7)}$	
		> 50	old	1000$^{7)}$	700$^{7)}$	300$^{7)}$	
Norway	--						
Austria	from 1984	> 50	new	800	450	350	
	from 1986	> 300	new	150	100	80	
	(draft)	150 bis 300		300	200	150	
		50 bis 150		400	300	200	
		> 300	old$^{10)}$	300	180	120	10) after 15000 h, at last 1 year after commissioning
		150 bis 300		600	350	250	
		50 bis 150		800	450	350	
Sweden (guideline)	from 1982		new	800$^{7)}$			
Swiss (draft)	from 1984	10 bis 100	new	500	450 HS/250 HL	250	
		>100		200	450 HS/250 HL	250	
EC-directive (proposed)	from 1.1.1985	> 50	new	800$^{11)}$	450	350	11) wet bottom boilers: 1300
	from 1.1.1996	> 50	new	400	220	180	

Appendix 2: DeNO$_x$ systems at utility boilers in the FRG (end of 1986) /19,20/

customer/location	capacity/ fuel/firing system	vendor/ process	start-up
Neckarwerke AG/			
Altbach unit #5	460 MW(e)/hard coal dry bottom boiler	Steinmüller/ SCR (High Dust)	IV/1985
Walheim unit #2	150 MW(e)/hard coal wet bottom boiler	Steinmüller/ SCR (High Dust)	1987
VEBA Kraftwerke Ruhr AG/			
HKW Buer	383 MW(t)/hard coal dry bottom boiler	Steinmüller/ SCR (High Dust)	I/1986
Knepper unit C	345 MW(e)/hard coal wet bottom boiler	Uhde-Lentjes/ Hüls-MHI/ SCR (High Dust)	III/1986 III/1986
Scholven unit F	120000 m^3/h/hard coal dry bottom boiler	SCR (High Dust)	1987
Scholven unit G,H	2x714 MW(e)/oil	Babcock SCR (High Dust)	I/1987
FKW Marl	214 MW(t)/hard coal wet bottom boiler	Exxon/SNCR	1986
TWS Stuttgart			
DKW Münster #12,#15	2x50 MW(e)/hard coal dry bottom boiler	EVT/ SCR (High Dust)	III/1986 IV/1986
DKW Münster #25	90 MW(e)/hard coal dry bottom boiler	EVT/ SCR (High Dust)	IV/1988
PREAG Heyden IV	800 MW(e)/hard coal dry bottom boiler	SHL/simultaneous SO$_2$/NO$_x$-process	IV/1987
Energieversorgung Oberfranken Arzberg #5, #7	237 MW(e)/lignite	DF-Uhde/ simultaneous SO$_2$/NO$_x$-process	I/1987
EWAG Nürnberg HKW Sandreuth	3x106 MW(t)/hard coal dry bottom boiler	Linde/ SCR (Tail Gas)	I/1987

HEW Hamburg HKW Hafen #2	66 MW(e) and 126 MW(t) hard coal dry bottom boiler	Steinmüller/ SCR (Tail Gas)	I/1987
KW Wedel unit #1 and #2	2x130 MW(e)/hard coal dry bottom boiler	Steinmüller/ SCR (High Dust)	IV/1987 I/1988
Energieversorgung Schwaben AG Heilbronn #7	720 MW(e)/hard coal dry bottom boiler	EVT/ SCR (High Dust)	IV/1986
Heilbronn #3,4,5,6	270 MW(e)/hard coal wet bottom boiler	Babcock/ SCR (Tail Gas)	1987
Großkraftwerk Mannheim AG unit #3, #4	440 MW(e)/hard coal wet bottom boiler	Deutsche Babcock/ SCR (Tail Gas)	1988
unit #7	475 MW(e)/hard coal dry bottom boiler	EVT/ SCR (High Dust)	1988
Isar-Amperwerke KW Zolling unit #5	450 MW(e)/hard coal dry bottom boiler	Uhde-Lentjes/ SCR (High Dust)	IV/1987
Bayernwerke München Schwandorf unit C and D	300 and 100 MW(e)/ lignite	Uhde-Lentjes/ SCR (High Dust)	II/1988
BEWAG Berlin Reuther West unit D,E	2x300 MW(e)/hard coal dry bottom boiler	Babcock/ SCR (High Dust)	IV/1988
Kraftwerke Mainz-Wiesbaden Kraftwerk Mainz #2,3	2x100 MW(e)/hard coal wet bottom boiler	Fläkt-Babcock/ SCR(Tail Gas)	IV/1987
Kraftwerk Mainz	127 MW(t)/hard coal wet bottom boiler	Babcock-Exxon/ SNCR	I/1986
STEAG Kraftwerk Walsum #9	410 MW(e)/hard coal dry bottom boiler	Uhde-Lentjes/ SCR (High Dust)	IV/1988

Kraftwerk Herne #4	500 MW(e)/hard coal dry bottom boiler	Babcock-Steinmüller/ fuel staging + SNCR	I/1989
Stadtwerke Frankfurt HKW West #2,3	90 MW(t)/hard coal dry bottom boiler	Uhde/Lentjes SCR (High Dust)	I/1989
HKW Hannover	2x130 MW(t)/hard coal	Uhde/Lentjes SCR (Tail Gas)	II/1989
Stadtwerke München KW München Nord #2	2x100 MW(e)/gas,oil	Babcock SCR (High Dust)	1988

LARGE SCALE TESTING AND DEVELOPMENT OF THE B&W LOW NOx CELL BURNER

M. J. Clark
A. D. LaRue
Domestic Fossil Operations
Babcock & Wilcox
Barberton, Ohio

A. D. Liang
Research & Development
Babcock & Wilcox
Alliance, Ohio

D. Eskinazi
Electric Power Research Institute
Palo Alto, California

ABSTRACT

Due to environmental concerns, fossil fuel power plants built prior to New Source Performance Standards (NSPS) may be required to reduce nitrogen oxide (NOx) emissions. A large segment of these units are equipped with cell burners which are producing relatively high NOx emissions, in the 1.0 to 1.8 lb/million Btu range. Babcock & Wilcox and EPRI have developed a low NOx burner that is directly retrofittable to cell burner units. This paper describes the continued development of this new burner.

Results of recent pilot combustion tests (100 MBtu/hr) conducted at EPA's Large Watertube Simulator (LWS) agree well with prior smaller-scale pilot performance. NOx reductions were typically 55 to 75 percent while achieving combustion efficiency of 99.5 percent in the test furnace. A full scale Low NOx Cell was installed at Dayton Power and Light's Stuart Station and has been in operation since March, 1985. The Low NOx Cell retrofit involves near-burner coal piping alteration but no pressure part modifications. At Stuart Station, the burner's operation and mechanical reliability has been demonstrated over a two-year period. A full scale retrofit demonstration is planned to confirm the commercial viability of this burner in a full scale retrofit.

INTRODUCTION

Since 1971 new units have come under federal regulation (NSPS) for NOx emissions. The imposed limits (modified in 1979) can be satisfied by the use of improved combustion systems. As a result of NSPS, many high NOx burner designs, such as the cell burner, were no longer offered commercially. The B&W cell burner was applied to 38 large, coal-fired utility boilers comprising over 26,000 MW's of

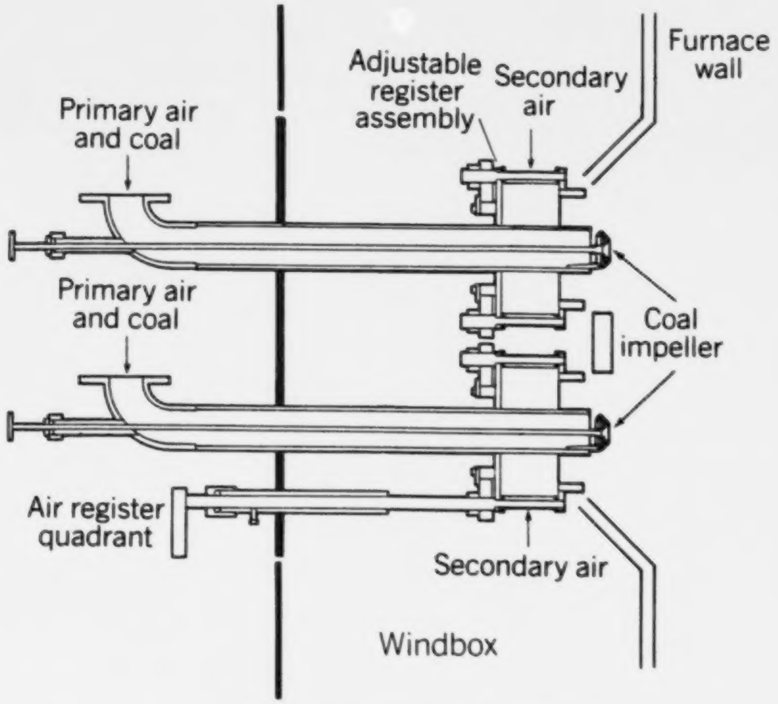


Figure 1 Standard cell burner.

generating capacity. These units are primarily situated in the northern and central portions of the United States, and generate NOx emissions which exceed present federal limits for new sources by factors of 2 to 3. Consequently, the cell burner equipped units are potential candidates for some measure of NOx emission control.

In many cases, low NOx burners could be retrofitted to pre-NSPS boilers. However, the cell burner's unique configuration makes it incompatible for retrofit with existing low NOx burners (Figure 1). The cell burner consists of two or three circular register burners combined into one vertically oriented assembly with the circular burner throats almost on tangent with one another. The burner throats are small (associated with high velocities) compared to low NOx designs, thus boiler pressure part modifications would be necessary to arrange and accommodate commercially available low NOx burners. The compact (high input per volume) furnace design, combined with firing 2 to 3 percent sulfur eastern bituminous coal (typical of cell-burner-equipped boilers) and poor secondary air distribution, have resulted in tube wastage in the combustion zone. These factors preclude the use of NOx ports and two-stage combustion for NOx control in these units.

The Electric Power Research Institute and Babcock & Wilcox have developed a retrofittable two-nozzle Low NOx Cell Burner. This "plug-in" design will fit existing wall tube openings eliminating outage time and material/labor expense associated with pressure part modifications and burner relocations. The first phase of this project focused on pilot scale (6 million Btu/hr) combustion tests to evaluate low NOx alternatives to the standard cell burner. Considerable work was performed to analyze slagging and corrosion risks, and to apply numerical models to predict full scale performance. Phase one results were reported during the 1985 Joint NOx Symposium (1). Since that time, the second phase of the project has been completed and is the subject of this paper. Phase two evaluated the B&W Low NOx Cell Burner in large scale (100 million Btu/hr) combustion tests; checked mechanical and operational aspects of performance in a full scale, single cell field retrofit; and studied issues related to total boiler retrofit of this burner.

PROGRAM OBJECTIVES

The prime objective of this program was to develop a combustion system capable of 50 percent reduction in NOx emissions which could be readily retrofitted to units equipped with two-nozzle cell burners. In principle this concept could be applied to three-nozzle cell burners with further development work. The combustion system was designed to facilitate retrofit application, i.e. minimize mechanical alterations to existing equipment, and simultaneously minimize the impact upon boiler operation and performance. A second objective was to develop the means to predict emission levels and associated boiler performance for the low NOx system when retrofitted. The third objective was to evaluate technical and economic factors associated with the low NOx system in the target boiler population.

To accomplish these objectives, a program was organized and conducted over a three year period which included the following tasks:

1. Pilot combustion tests were carried out at two scales to evaluate alternatives and verify emission performance.
2. One full scale prototype Low NOx Cell was installed at Dayton Power and Light's Stuart Station to verify operation/mechanical reliability.
3. Furnace wall tube corrosion potential was evaluated by lab scale corrosion experiments and in-furnace gaseous species measurements taken during the combustion tests.
4. A numerical analysis was made to predict full scale emissions and heat transfer performance.
5. An engineering study was conducted to assess technical and economic risk for commercialization.

The first scale of combustion tests were conducted at 6×10^6 Btu/hr and identified a burner capable of meeting the program goals. This burner, the Low NOx Cell, is shown in Figure 2. The concept of this burner is to fire all the fuel through an enlarged coal pipe in the lower throat. The fuel input of the large nozzle equalled the sum of the fuel input of the two burner nozzles in the standard cell in order to maintain the same firing rate. A portion of the secondary air was also introduced in the lower throat, through a slide damper which controlled flow rate and adjustable vanes which controlled swirl. The lower throat assembly is based on the B&W "S" burner, a commercial design used for mechanical enhancements without NOx reduction. The upper throat like an integral NOx port supplied the balance of secondary air. The upper throat assembly used a sliding damper to control flow rate and tilting vanes to control air mixing rate with the lower throat flame.

In these small-scale tests, reductions of NOx emissions greater than the 50 percent were easily achieved with moderate increases in flame length. The Low NOx Cell proved to be flexible in terms of fuel fired and operability. (Refer to Reference 1 for a complete discussion).

LARGE SCALE COMBUSTION TESTS

Large scale combustion tests were conducted to reduce scale up risks and improve predictive capabilities at full scale by means of a comparative evaluation of two

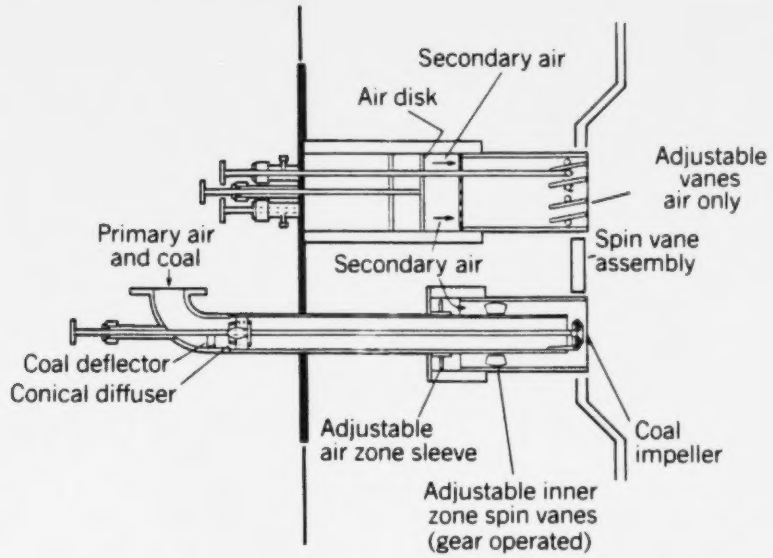

Secondary air
Air disk
Adjustable vanes air only
Primary air and coal
Secondary air
Spin vane assembly
Coal deflector
Conical diffuser
Adjustable air zone sleeve
Adjustable inner zone spin vanes (gear operated)
Coal impeller

Figure 2 Low NOx cell burner.

cell burner designs; the standard cell burner and the Low NOx Cell Burner developed at 6 x 10^6 Btu/hr. The same two fuels, that were used in small scale tests, Ohio No. 6 and Lower Kittaning were used in these tests.

Several criteria were used in making the comparative evaluations between the standard cell and the Low NOx Cell including:

- NOx reduction
- Combustion efficiency
- Flame length
- Fuel adaptability
- Presence of corrosive atmospheres
- Operability and flexibility

Experimental Systems

The cell burner arrangement tested was a two-cell high by two-cell wide array of two-nozzle cells on the front wall of the test facility, shown in Figure 3. This multiple burner array was used to evaluate burner-to-burner interactions, expected with the closely spaced cell burner design. In this four-cell (eight-nozzle) arrangement each cell had a firing rate of 25.0 x 10^6 Btu/hr, approximately one-tenth the size of a typical full scale cell.

Standard Cell Burner. The two-nozzle standard cell burner (see Figure 1) and the burner spacing were scaled down directly from a typical operating boiler at the Dayton Power and Light Company's Stuart Station. Standard cell burners provide for high velocity turbulent mixing to promote rapid combustion. Coal, transported by primary air, enters the burner through a 90° elbow which is connected to an axial coal nozzle. An impeller with a 75° included angle, located at the end of the coal nozzle, disperses the coal radially outward into the secondary air stream. Secondary air from the windbox passes through an adjustable register of radial vanes into an annular passage around the coal nozzle. The register assembly acts as both a swirl generator and flow control device.

Low NOx Cell Burner. The Low NOx Cell Burner was designed to be easily retrofitted into existing standard cell burner locations. The key feature of the

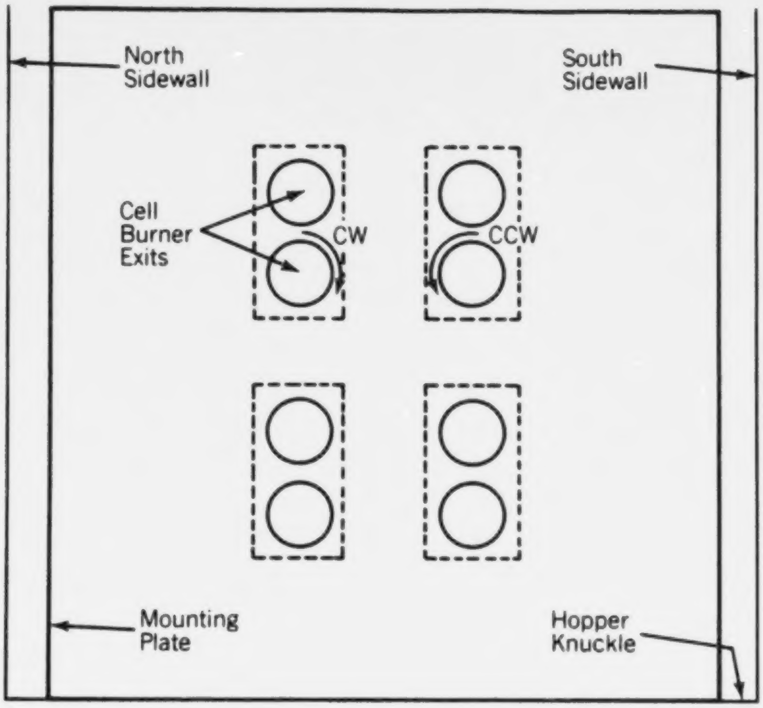


Figure 3 Cell burner arrangement on firing wall in LWS viewed from furnace cavity.

design, shown in Figure 2, is the elimination of the upper coal nozzle from the standard cell, leaving only air flowing through the upper throat, and all the fuel fired through an enlarged coal nozzle in the lower throat. The result is a burner with an integral air port for staged combustion. The low NOx burner assembly includes the following components and controls for the burner throat and air port:

- 25 x 10^6 Btu/hr coal nozzle with movable impeller.
- Adjustable spin vanes in the lower throat for swirl generation and flow control.
- Adjustable sliding dampers for both the upper and lower throat for air flow distribution control.
- Adjustable directional vanes to guide upper throat airflow either parallel, divergent, or convergent to the flame.

Test Facility

The Large Watertube Boiler Simulator (LWS) is shown in Figure 4. The LWS is owned by EPA; and operated by Energy and Environmental Research Corporation. The windbox used in the LWS combustion tests was physically divided into four compartments. Each compartment was supplied with preheated combustion air that was independently controlled with a damper and individually metered with a venturi flow meter. The burners were installed in an opposed swirl arrangement. Viewed from the burner firing front, the burners on the left, or south side, had the secondary air swirl in a clockwise direction, while the burners on the right, or north side, had the secondary air swirl in a counterclockwise direction.

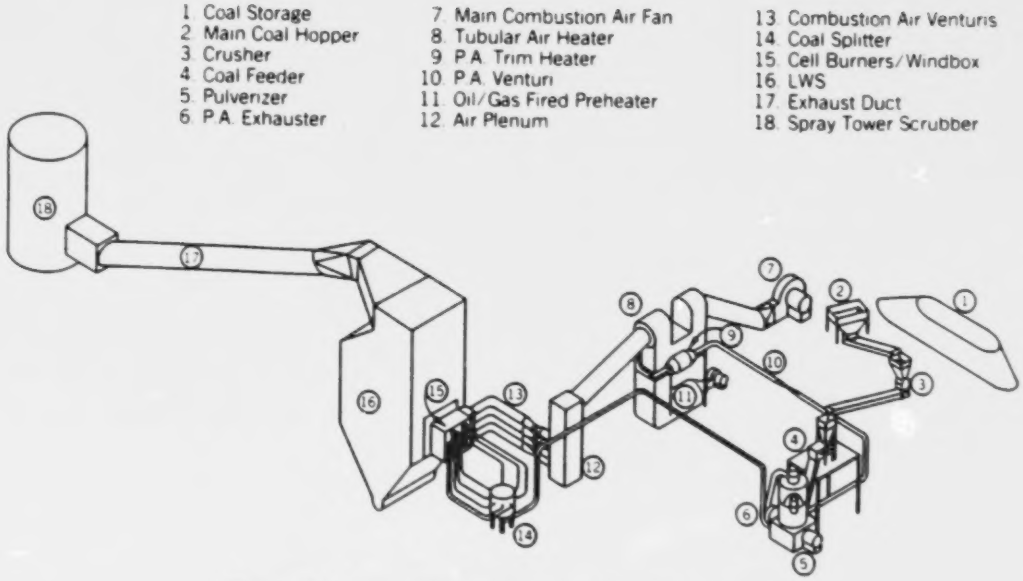

1. Coal Storage
2. Main Coal Hopper
3. Crusher
4. Coal Feeder
5. Pulverizer
6. P.A. Exhauster
7. Main Combustion Air Fan
8. Tubular Air Heater
9. P.A. Trim Heater
10. P.A. Venturi
11. Oil/Gas Fired Preheater
12. Air Plenum
13. Combustion Air Venturis
14. Coal Splitter
15. Cell Burners/Windbox
16. LWS
17. Exhaust Duct
18. Spray Tower Scrubber

Figure 4 Large watertube boiler simulator facility.

The primary air and coal were supplied from a single 14-inch pipe from the pulverizer to a coal splitter installed near the burner front. The total primary air flow was controlled and metered at the pulverizer with a damper and venturi meter. The coal splitter, designed and fabricated by B&W, divided the coal and primary air flow into eight streams. Each of eight outlets from the splitter supplied one nozzle of the standard cell burners. Two outlet hoses were paired at the burner for the low NOx configuration since each Low NOx Cell utilizes a single coal nozzle.

Test Coals

The combustion tests of the cell burners in the LWS were conducted with two coals, Ohio No. 6 and Lower Kittaning. The analysis of the fuels fired are given in Table 1. These two coals represent the typical range of composition for cell-burner-equipped boilers. The key NOx influencing factors are volatile matter content and the Fixed Carbon/Volatile Matter (FC/VM) ratio (2). The Ohio No. 6 is ranked as a high-volatile A bituminous coal, with about 43.3 percent volatiles (on a dry basis) and and FC/VM ratio of 1.05. On the other end of typical coal characteristics, the Lower Kittaning coal is ranked a medium-volatile bituminous coal with about 24.5 percent volatiles (on a dry basis) and a FC/VM ratio of 2.5. The heating value of the two fuels is similar, about 13,000 Btu/lb (on a dry basis) as is the fuel nitrogen, abut 1.2 percent (on a dry basis). The ash content was higher for the Lower Kittaning coal, about 15 percent compared to 11 percent on a dry basis for the Ohio No. 6 coal, while the sulfur content was lower, 3.7 percent compared to 5.0 percent for the Ohio No. 6 coal.

BURNER PERFORMANCE

The performance of the Low NOx Cell Burner was evaluated in a series of tests outlined in Table 2. Included as an integral part of this evaluation were tests of a standard cell burner. Characterizing the performance of the standard cell burner in the LWS provided a basis for evaluating the Low NOx Burner and extrapolating its performance in the LWS to operating boilers. Two Low NOx Cell Burner configurations were evaluated. The two arrangements differed only in

Table 1
Composition of Test Coals

Basis	Ohio #6 Coal As Received	Lower Kittaning Raw Coal As Received
Proximate (wt%)		
Moisture	2.37	1.04
Ash	10.48	15.12
Volatile	42.35	23.73
Fixed C	44.82	60.11
Heating Value		
Btu/lb	12,860	12,959
MMF Btu/lb		
MAF Btu/lb		
Ultimate (wt %)		
Moisture	2.37	1.04
Carbon	69.12	72.34
Hydrogen	5.09	4.37
Nitrogen	1.18	1.12
Sulfur	4.82	3.80
Ash	10.46	15.12
Oxygen*	6.96	2.21
Forms of Sulfur (wt %)		
Sulfate	0.17	0.43
Pyritic	2.49	2.42
Organic	2.16	0.95

*Oxygen determined by difference

Table 2
Test Matrix for the Scale-Up Burner Tests

Burner	Standard Cell	Low-NO_x Cell		
Burner Configuration	Normal	Normal (AFAF)	Inverted (AFFA)	Optimum (AFAF)
Firing Rate (10^6 Btu/hr)	60-100	100	100	60-100
Excess O_2 (%)	3.0-5.0	3.0	3.0	3.0-5.0
Burner Adjustments	Fixed	Vary	Vary	Optimum
Coal	Ohio No. 6 Lower Kittaning	Ohio No. 6	Ohio No. 6	Ohio No. 6 Lower Kittaning
Standard Measurements	All Tests	All Tests	All Tests	All Tests
Furnace Probing for Reduced Species	Full Load and 3% O_2 for Both Coals	Minimum NO_x Condition	Minimum NO_x Condition	Full Load and 3% O_2 for Lower Kittaning Coal

orientation of the cells. In the "normal" configuration, each cell was positioned with the coal nozzle/spin vane assembly in the lower throat. This normal configuration thus results in an alternating air-fuel-air- fuel (AFAF) pattern from the top to the bottom row along each column of cells. In the second configuration, the lower two cells were inverted such that the coal nozzle/spin vane assembly was above the air port. This arrangement, air-fuel-fuel-air (AFFA), surrounds the fuel-rich burners with air ports both above and below. This alternate arrangement was expected to affect the air/fuel mixing characteristics in the lower furnace, possibly enhancing emission reduction as well as promoting an oxidizing atmosphere along the walls in the lower furnace.

Standard Cell (Baseline Tests)

The standard cell burner design was evaluated to establish a baseline level of performance in the LWS. The objective of these tests was to characterize typical performance, and not to optimize the burner settings for low emissions by biasing air or coal distribution among the different throats. There was no significant effect of burner settings on performance during a brief series of adjustments, typical of reported performance from operating boilers. Thus, a single register and impeller position was used for all standard cell burner characterization tests. At nominal full load with the Ohio No. 6 and Lower Kittaning coals, NOx emissions were 795 ppm and 830 ppm (@ 3 percent O_2), respectively. These emission levels are on the low end of typical field NOx emissions. Observed flame lengths, although very difficult to quantify, were 10-12 feet in the pilot furnace.

Low NOx Cell (Parametric Tests)

A series of screening tests conducted for each configuration demonstrated the flexibility of the Low NOx Cell Burner with its adjustable parameters. The effect of these parameters is summarized below:

- Impeller Design: The design of the coal impeller was a critical parameter in determining flame shape and operating characteristics. Two impellers were tested: 50 and 25 degree included angle. The impeller with a 50 degree included angle tended to produce shorter flames with correspondingly higher NOx emissions than the 25° impeller. The steeper angle was more effective in dispersing the coal into the swirling combustion air stream. Impeller position had no significant effect over the range investigated.

- Spin Vane Position: The spin vane position was the dominant parameter used during this test program to control air flow distribution between the upper and lower throat of each cell. Closing the spin vanes not only increased the degree of the swirl but also increased pressure drop across the lower throat. This forced more air to be diverted to the upper throat, the integral staged air port. This reduced the burner zone stoichiometry and thus decreased NOx emissions.

- Lower Damper Position: The lower damper adjustments were limited during these tests. Due to the pilot burner scale, the degree of accuracy in damper positioning was limited. However, this device did demonstrate that it could provide a similar degree of control as the spin vanes. Closing the lower damper 96 percent produced a flow restriction comparable to a spin vane position of 60 degrees with correspondingly similar NOx emissions.

- Directional Vane Position: The directional vanes in the upper throat proved to be an effective means for flame shaping and NOx control. Diverting the staging air away from the flames tended to decrease NOx emissions and increased flame length. This was particularly true for the directional vanes in the upper two cells.

- Upper Damper Position: Upper damper adjustments were limited during these tests due to excessive windbox-to-furnace differential when closed 50 percent or more. Closing the upper damper, in any case, was not desirable from an emission standpoint. By increasing the restriction of air through the upper throat, the burner zone stoichiometry increases as do NOx emissions.

The burner variables evaluated during these screening tests produced a wide range of NOx emissions and flame lengths. A close relationship of NOx to observed flame length is shown in Figure 5 for full-load operation at an overall stoichiometry (SR_T) of 1.17. The NOx varied from about 820 ppm with a flame length of 10 feet down to a minimum of 205 ppm with a flame length of 22 feet. While it is impossible to quantitatively predict the Low NOx Cell's impact on flame length at full scale, pilot trends are representative. However, the flexibility of the low NOx burner design and controls allow tuning burner performance to the field application (i.e. maximize NOx reduction and avoid flame impingement).

Performance of the cell burner configurations evaluated during this program is summarized in Table 3 for nominal full load conditions with Ohio No. 6 coal. Up to 75 percent reduction in NOx emissions was achieved by the Low NOx Cell Burners with the 25° impeller. The flame length at this minimum NOx condition was about twice that for the standard cell burner. However, NOx control was only one of the selection criteria.

Optimum Low NOx Cell Configuration

The configuration selected as optimum was the normal air-fuel-air-fuel burner arrangement equipped with the 50° impeller. This optimum configuration achieved 55 percent reduction in NOx with a 60 percent increase in flame length. The high firing density of a full scale unit would tend to lessen the increase in flame

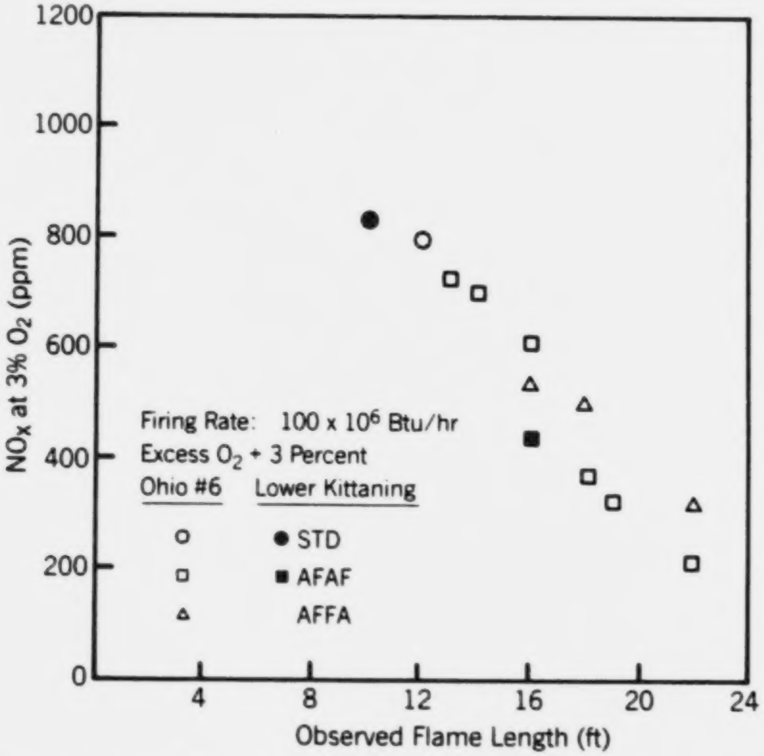


Figure 5 Correlation of NO_x emissions with observed flame length.

Table 3
Summary of Performance for Cell Burner Configurations
Evaluated at Nominal Full Load Conditions
with Ohio No. 6 Coal

Parameter	Standard Cell	AFAF* (50° Impeller)	AFAF (25° Impeller)	AFFA (25° Impeller)
NO_x ppm at 3% O_2 lb/10^6 Btu	795 1.04	360 0.47	270 0.35	205 0.27
CO ppm at 3% O_2	35	40	35	35
Flame Length (ft)	10-12	16-18	22	22
Fly Ash Carbon (% C in ash)	1.87	3.89	5.05	6.60
Lower Furnace H_2S Pts. Meas/Tot. Pts Range (ppm)	 1/6 175	 3/13 615-936	 5/11 2300-4230	 4/12 435-5215

*Selected optimum condition

length with the Low NOx Cell. Flame stability was very good over expected load and excess air ranges. There was a slight decrease in combustion efficiency as indicated by fly ash carbon content. Based on previous tests in the LWS at 100 x 10^6 Btu/hr, the level of burnout achieved by both burners was exceptionally good. (Generally, higher unburned carbon results in LWS tests because of the lower furnace temperatures in comparison with full scale units.) Probing in the lower furnace for reduced species indicated only three of thirteen sample locations with measurable concentrations of hydrogen sulfide (H_2S), an indicator of corrosion (3). Two of the locations at which H_2S was measured for this optimum Low NOx Cell Burner were not sampled for the standard cell burner. Further, the measured concentrations of H_2S at each of these three locations was below 1000 ppm, indicating little potential for corrosion.

The emission performance characteristics are compared for the optimum Low NOx Cell Burner and the standard cell burner in Figures 6 and 7 for Ohio No. 6 coal and Lower Kittaning coal, respectively. The emissions data are presented as a function of excess air for several firing rates. Although the NOx emissions are about 55 percent lower with the low NOx burner, the effect of excess air is similar for the two burners with each coal. In addition, NOx emissions are slightly higher with the Lower Kittaning coal for both burner designs. The effect of firing rate, shown in the two figures, is substantially different. The NOx emissions from the standard cell burner are much more sensitive to firing rate than the optimum Low NOx Cell Burner. Staged burners, such as the Low NOx Cell Burners, achieve low emissions by delaying mixing. This results in extended fuel-rich zones with lower average flame temperatures. Thus, these low NOx burners tend to minimize thermal NOx formation and are less sensitive to local thermal environment (4,5). Generally, CO emissions were low for all test conditions (Standard and Low NOx Cells firing both coals).

Combustion efficiency for the two burner types is compared in Figure 8. At nominal full load, 100 x 10^6 Btu/hr, fly ash carbon content was less than 4 percent with both coals for the two burner types. The burnout for the standard cell burner with Ohio No. 6 coal was even better, with less than 2 percent carbon in the flyash for the entire range of excess air evaluated. The efficiency of the high turbulence standard cell burner was also better at lower loads than the optimum Low NOx Burner. The mixing of fuel and air is delayed by design in the Low NOx configuration and some compromise in efficiency could be expected. In addition, the thermal characteristics of the LWS tend to amplify such differences

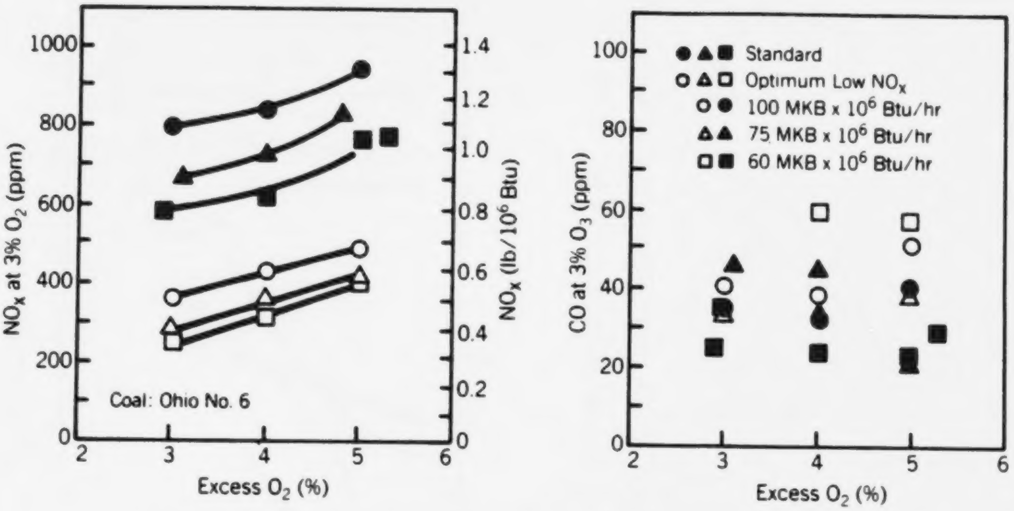


Figure 6 Comparison of emissions from the standard cell burner and optimum low-NO_x design with Ohio No. 6 coal.

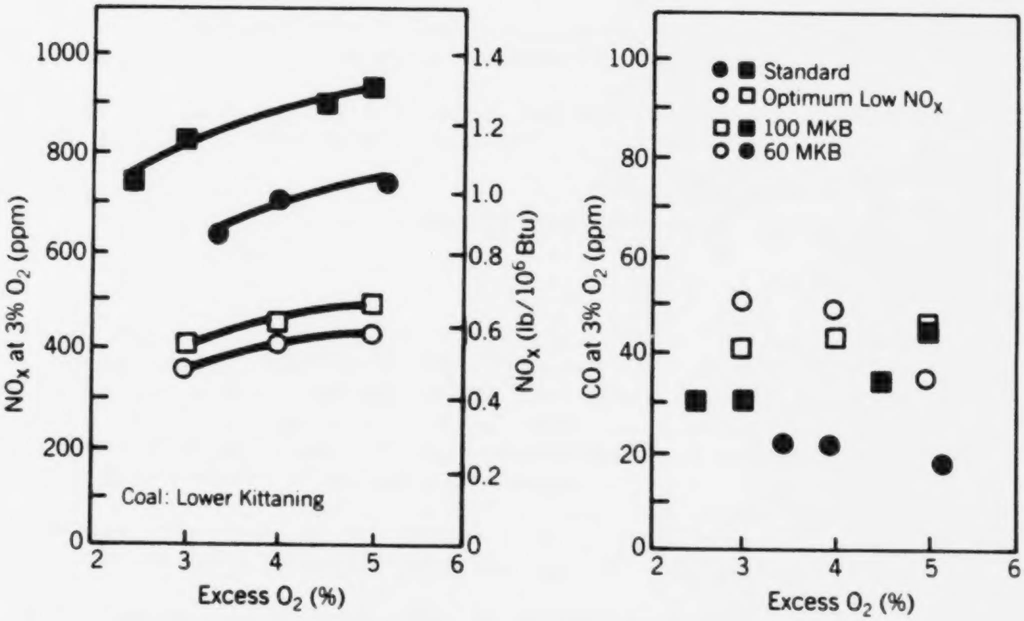


Figure 7 Comparison of emissions from the standard cell burner and optimum low-NO_x design with Lower Kittaning coal.

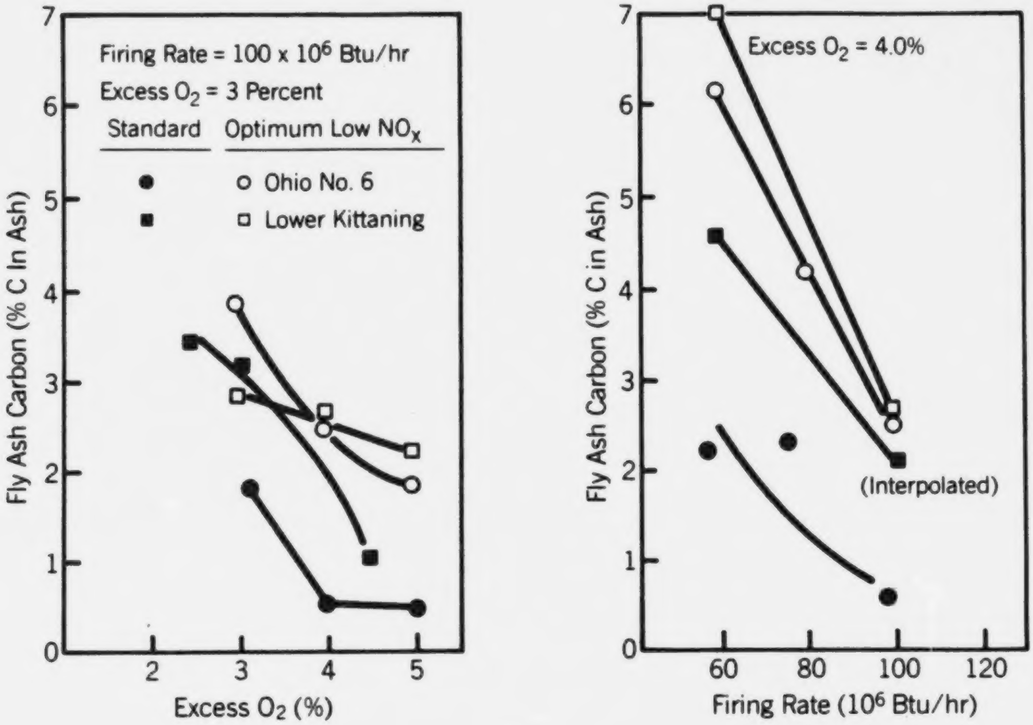


Figure 8 Comparison of combustion efficiency with the standard cell burner and optimum low-NO_x configuration.

at low load. In that regard, the carbon burnout achieved in the LWS can be considered as a worst case example compared to operating boilers.

PROTOTYPE EVALUATION

In March of 1985, a full scale, two-nozzle cell burner was replaced with a Low NOx Cell at Dayton Power & Light's Stuart Station No. 3. This burner has now been in operation for two years. Evaluations of the burner include mechanical reliability, corrosion checks of furnace tubes surrounding the cell opening, visual observations of flame, air flow measurements of secondary air, and temperature measurements of burner components.

All mechanical components of the burner have operated properly throughout the past two years and are staying within material temperature limits.

In a low NOx scheme, where combustion is staged, reducing atmospheres will be present, possibly accelerating corrosion rates on furnace wall tubes. Because of the concerns about corrosion, ultrasonic (UT) measurements of furnace tubes were taken to document metal thickness before installation and after one year of operation. This unit has had a history of tube wastage in the furnace due to reducing atmospheres, especially along the side walls. The location of the burner with respect to the furnace (Figure 9) coupled with the design of the windbox, causes this burner to receive less than its share of combustion air. The air flow measurement device, integral to the burner, indicates that it is operating at a total stoichiometry of 0.81, a worst case scenario for corrosion. The UT measurements performed after one year by DP&L's own nondestructive testing team

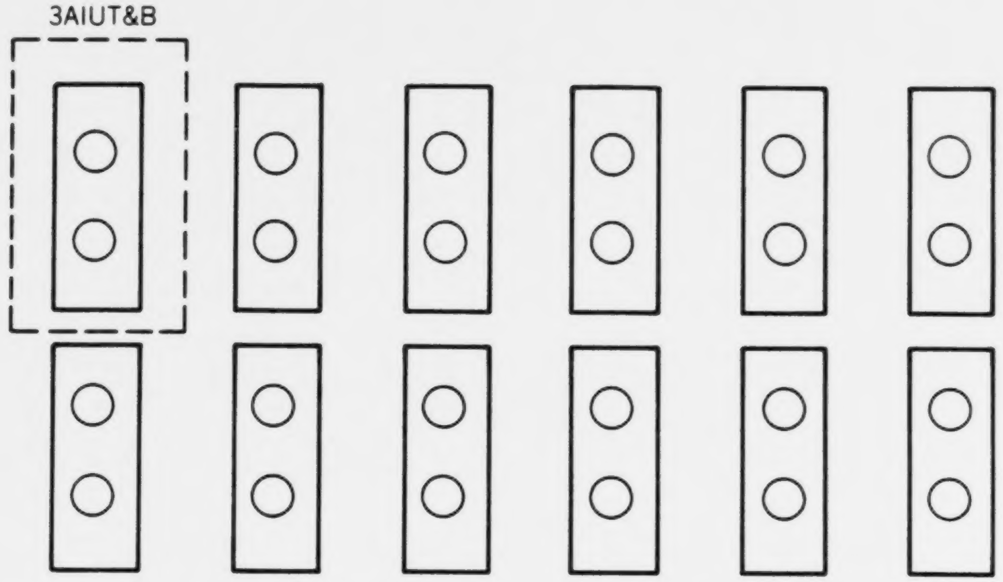


Figure 9 Location of low-NO_x cell burner on front wall.

showed that virtually no tube wastage had taken place, thus DP&L felt no steps would need to be taken to prevent corrosion due to the burner.

Visual observations of the burner flame at the Stuart Station are difficult since the wraparound windbox does not allow conventional observation ports on the side walls in the combustion zone. However, observations from the upper furnace and through the burner barrel indicate that the Low NOx Cell flame is stable and originates at the throat. A specially designed side wall port is being installed through the windbox at a location close to the Low NOx Cell. Utilizing a fiber optic probe through this port, better observations will be made of the flame.

ENGINEERING FEASIBILITY

Included in the program was a study of the technical feasibility of retrofitting Low NOx Cells on an entire unit equipped with cell burners. This study looked specifically at DP&L's Stuart Station as the candidate unit for a full retrofit since it was very representative of cell burner units. The average cell-equipped unit is 700 MWe and has 24 burners. (Stuart Station is 610 MWe and has 24 burners.). The study considered performance, operations, and maintenance with the proposed retrofit of the Low NOx Cell.

Of utmost importance to any utility is the ability of its boilers to convert heat available in the fuel to steam. Since carbon contributes the majority of heat in coal, its utilization must be maximized. Unburned carbon in ash would be estimated at 1 to 3 percent for a cell unit equipped with Low NOx Cells. This is based on the combustion tests at two scales and known data from standard cell burner units.

The main goal of the new burner is to reduce NOx by at least 50 percent. At both pilot scales, this level of reduction was achieved with acceptable increases in flame lengths. A field unit could expect a reduction in NOx emissions of the same magnitude with this new burner. Combustion tests also showed no appreciable change in furnace exit gas temperature.

Based on UT measurements taken around the Low NOx Cell at Stuart Station and gaseous species measurements in the pilot combustion tests, no corrosion problem would exist with a full retrofit. Maintenance costs associated with corrosion therefore will not increase.

If the flame of a low NOx burner is too long, it may impinge on the furnace walls, causing slagging and possible corrosion. Based on the combustion tests, flame lengths on a full scale boiler are expected to be easily accommodated within the confines of the furnace.

Another consideration when retrofitting new burners is the added resistance of the burners. The reserve fan capacity of a unit must be able to overcome the added pressure drop and maintain the quantity of air flow desired. The Low NOx Cell does have higher resistance than the standard cell, requiring a 2-3 inch W.G. (51-76 kg/m^3) additional pressure. When considering a total drop for the secondary air system of a 20-inch W.G. (510 kg/m^3) or more, the additional resistance should be well within the range of capacity for the fan. In addition, these pressurized furnaces have low windbox-to-furnace differentials leading to poor air distribution. The higher resistance burners will serve to improve distribution, which may aid corrosion prevention, and improve overall combustion.

The technical feasibility of retrofitting a cell burner unit with low NOx Cells is very high. Further, considering the design and age of pre-NSPS burners in general, retrofitted low NOx burners could represent a reduction in maintenance costs.

CONCLUSIONS

A comparative evaluation of B&W standard cell and Low NOx Cell Burners was successfully completed in the LWS facility at EER's test site. The Low NOx Cell Burner was tested over a wide range of operating conditions and achieved the goals of the test program. In addition, the available controls allow flexibility in tuning burner performance (NOx and flame length) to specific applications. The Low NOx Cell burner demonstrated the following performance relative to the standard cell burner in these combustion tests:

- NOx emissions were reduced 55 percent with about a 60 percent increase in flame length at the optimum burner configuration selected in this program. One of the burner configurations achieved up to 75 percent NOx reduction with a factor of two increase in flame length.

- Combustion efficiency as indicated by the unburned carbon (UBC) content in the fly ash, was good for both the standard and Low NOx Cell Burners. Optimum low NOx operating conditions yielded 3.89 percent UBC content in fly ash, comparatively low for typical LWS burner tests.

- Flame stability was very good for the Low NOx Cell and the standard cell burner over similar operating conditions for both coals tested.

- Reducing conditions in the lower furnace, as determined by local hydrogen sulfide measurements, increased slightly with the low NOx configurations. Hydrogen sulfide concentration was less than 1000 ppm for the optimum Low NOx Cell Burner at all sample locations, indicating no major concern for fireside corrosion.

- In a full scale application, the following performance is anticipated: (1) NOx emissions reductions comparable to pilot scale results on a percentage basis, (2) similar flame length trends as observed at pilot scale, (3) unburned carbon and CO emissions less than those obtained at pilot scale, and (4) no significant increases in furnace corrosion.

ACKNOWLEDGMENTS

The authors wish to acknowledge the contributions made to this program by EER, and in particular to A. Abele of EER.

REFERENCES

1. LaRue, A. D., and Rodgers, L. W., "Development Low NOx Cell Burners for Retrofit Applications", 1985 Joint Symposium on Stationary Combustion NOx Control, EPRI Report CS - 4360, Volume 1, January 1986, page 17-1.

2. Chen, S. L., et al, "Influence of Coal Combustion on the Fate of Volatile and Char Nitrogen During Combustion," Nineteenth Symposium (International) on Combustion, The Combustion Institute, 1982.

3. S. F. Chou, et al, "Fireside Corrosion in Low NOx Combustion Systems", 1985 Symposium on Stationary Combustion NOx Control, EPRI Report CS- 4360, Volume 1, January 1986, page 19-1.

4. Zeldovich, T., "The Oxidation of Nitrogen of Combustion and Explosions," Acta Physiocochimica, URSS, 21, p. 577 (1946).

5. Pershing, D. W., and Wendt, J. O. L., "Pulverized Coal Combustion: The Influence of Flame Temperature and Coal Composition on Thermal and Fuel NOX," Sixteenth Symposium on Combustion, Combustion Institute, Pittsburgh, Pennsylvania (1977) p. 389.

LOW NOx DEVELOPMENTS ON AN INTEGRATED COMBUSTION AND ENVIRONMENTAL TEST FACILITY

J. Vatsky
Foster Wheeler Energy Corporation

R. McMillan
Foster Wheeler Development Corporation

ABSTRACT

A test facility, equipped for a wide range of combustion and emission-control related testing, has been in operation for approximately eighteen months, firing a wide variety of pulverized fuels, from sub-bituminous coals to very low volatile fuels such as petroleum coke. Initially, an extensive test program was performed with both petroleum coke and bituminous coal with an arch-fired furnace configuration. More recently, testing has begun with a two-burner high horizontally-fired configuration. Although these programs were designed to evaluate NOx emissions, and levels of about 0.15 lb/million Btu have been obtained, the Combustion and Environmental Test Facility is also designed to facilitate testing of SO_2 control systems.

This paper describes the CETF and summarizes initial results obtained from both the arch-and horizontally-fired modes.

INTRODUCTION

In recent years, the environmental community has exerted greater pressure on the consequences and, therefore, sources of acid rain. Under immediate scrutiny came the combustion methodologies of fossil fuels--specifically coal--and the associated flue gas cleaning techniques for control of sulfur oxides of nitrogen, the principal precursors of acid rain. With the need for advanced combustion technology research apparent, the Foster Wheeler Energy Corporation designed and built a Combustion and Environmental Test Facility (CETF) for development and testing of combustion and pollutant emission control equipment. The facility, jointly staffed and funded by Foster Wheeler Energy Corporation (FWEC) and Foster Wheeler Development Corporation (FWDC) is located in Dansville, New York, at the FWEC manufacturing facility.

In the past FWEC has performed new equipment developmental activities either at the commercial scale, on industrial or utility steam generators, or by renting large test facilities. Although quite satisfactory for development of FWEC's first and second generation low NOx burners, more advanced work for:

- Burner development
- Low NOx furnace design evaluations
- SO_2 control via dry sorbent injection
- Fuels evaluations
- Customer support and problem analysis
- Integrated combustion/emissions control testing

necessitates in-house facilities.

Consequently, the CETF was developed and is now in full operation.

Historically Foster Wheeler has been the primary supplier of steam generators to fire low volatile fuels much as petroleum coke and anthracite. The type of furnace configuration used for these fuels is the arch-fired design, such as the 150 MW pet-coke unit shown in Figure 1. Since arch-firing is an inherently low NOx method of firing all fuels, the CETF's furnace incorporated an arch to permit both basic emissions testing to be performed on this configuration and investigations of other advanced low emission techniques.

The CETF's furnace, shown schematically in Figure 2 with cyclone-separator arch burners and in Figure 3 with two horizontally-fired burners, is arranged to produce conditions which closely match those of commercial equipment. These include:

- Furnace residence time is limited to about 2 sec. max. between the burner centerline and furnace exit.
- Furnace Exit Gas Temperature (FEGT) is about 2200°F and can be varied, by adjusting total furnace absorption.
- Burner/furnace aerodynamics are similar to those of commercial equipment as are:

- o Furnace mixing patters, due to both overall geometry and the two burner high arrangement.

The arch configuration, which is required to provide proper conditions for low volatile fuel combustion, is also important to produce the desired velocities/residence times and FEGT. The reduced upper furnace cross-section is responsible for the increased velocity and resultant decreased residence time. Decreased upper furnace heat transfer surface reduces absorption above the burner zone thereby increasing FEGT to levels normally achieved in commercial equipment.

Although not currently equipped with a superheater, the unit has screen tubes at the furnace exit followed by a water-cooled economizer. These yield realistic gas quenching rates. In this way all flue gas constituents, gaseous and particulate, are comparable to field equipment.

Commercial practices, used through the CETF system design, have been mated with research-oriented considerations wherever practicable in order to maximize the usefulness and flexibility of the system.

The initial testing at the CETF was performed in 1985 and 1986 and was intended to investigate and perfect combustion techniques of a low volatile fuel (Petroleum coke) and of bituminous coal while firing in an arch-type configuration. Upon completion of that test series, the furnace front wall was modified to accept two (2) horizontal burners. Shakedown began in early December, 1986, followed by a test program funded by a utility customer.

The first test series using the CETF was with delayed petroleum coke as fuel. These tests, intended to characterize flame stability under various combustion conditions and determine emissions of gaseous combustibles, was performed for a customer who had purchased an arch-fired Foster Wheeler boiler designed to burn petroleum coke. Petroleum coke has been used as a boiler fuel over the past 50 years. In 1980 approximately 15.2 million tons of petroleum coke was produced in the United States, with 1.1 million tons used as a fuel in the U.S. and another 4.6 million tons overseas. Typically, petroleum coke is characterized by high carbon content, high sulfur, and low volatility. A typical coke analysis appears in Table 1. Because of the low volatility of the fuel, petroleum coke is often burned with arch-firing equipment to achieve satisfactory flame stability and carbon burn-out.

After the pet-coke tests were completed, testing of a middle Kittanning bituminous coal was commenced in the arch-fired mode. An analysis of the bituminous coal utilized is shown in Table 2. Although bituminous coal is typically burned in the horizontally-fired configuration, FWEC has been called on in the past to design arch-fired furnaces for utility applications utilizing bituminous coal. This firing method has been demonstrated as an inherently low NOx technique which also produces low unburned carbon. Although an extensive development program was not undertaken, sufficient evaluations were performed to confirm the low NOx characteristics with bituminous coal and describe the operating performance of a new arch-fired burner design for low NOx combustion of both petroleum coke and bituminous coals.

Subsequent to the arch-fired tests, completed in July 1986, the CETF was shutdown for installation of a new front wall, below the arch, containing the two horizontally fired burners. Additionally, the firing system was upgraded to permit firing a much wider range of fuels, including high ash/high moisture sub-bituminous coals. The system controls have also been enchanced with inclusion of an industrial IBM PC/AT and an automated Data Acquisition System.

FURNACE

The CETF utilizes a direct-fired system (i.e., hot-primary-air-swept ball mill) feeding either a single 75 x 10^6 Btu/hr arch-fired twin-cyclone burner assembly or two 40 x 10^6 Btu/hr horizontally-fired burners. The fuel is fired into a refractory-lined water-jacketed furnace, as illustrated in Figs. 2 and 3. The water jacket operates under water-head pressure and utilizes natural circulation. Steam produced is vented to atmosphere through a steam drum situated above the furnace. As shown in Figure 4. combustion gases leaving the furnace pass over horizontal, conventive tube surfaces (economizer) cooled by forced-water circulation. The effluent gases then pass through a two-stage air heater (a tubular air heater followed by a heat pipe air heater), a baghouse dust collector, an induced-draft fan, and then the stack. The level of sulfur dioxide in the effluent is controlled by injecting a sodium-based sorbent into the gas stream prior to the baghouse. In addition to back-end sulfur dioxide cleanup, the CETF has the capability of furnace injection of sorbents for evaluation of in-situ sulfur dioxide control. Typical CETF operating conditions are tabulated in Table 3.

The Arch-Fired Configuration

Combustion conditions in the furnace are controlled by several means: excess air, primary air distribution, secondary air distribution and overfire air. A typical windbox/burner assembly for the arch-fired configuration is shown in Figs. 2 and 6. Within this configuration, the burner fuel exit velocity vector is controlled by the position of a swirl control plug with straightening vanes and by the quantity of primary air passed through the burner (burner vent damper). The plug can be moved axially to control the swirl of fuel leaving the burner and hence the change of air/fuel mixing at the burner exit. The primary air can be split at the burner by manipulation of the burner vent damper. With the vent damper closed, the burner primary air-to-fuel ratio and fuel/air velocities are at their maximum. When the vent damper is opened, a portion of the primary air bypasses the burner and enters the furnace through vent pipes adjacent to the burner nozzles. As the vent is opened further, fuel velocity drops and primary air entering with the fuel decreases. Thus the positions of the burner plug and bypass damper affect the turbulence and air/fuel mixing at the burner exit, the ignition point, and the depth the flame penetrates into the furnace.

With the arch-fired configuration, secondary air-flow into the furnace is controlled by adjustment of dampers inside the windbox. As shown in Fib. 6, air-flow distribution is controlled in the vertical windbox plane by three dampers. The three vertical plane control dampers regulate the air distribution to the flame along its downward path; thus they can be used to control the rate and staging of combustion and can also affect the position of the flame in the furnace.

These various control mechanisms can individually or collectively affect the initial combustion point, the rate of combustion, and the location of the flame in the furnace. The most desirable arrangement of these controls is one which results in a flame that ensures the most uniform heat release, a low peak flame temperature, and the greatest combustion efficiency.

The Horizontally-Fired Configuration

Combustion control is essentially the same as with the arch-fired configuration.

However, as shown in Figure 3, the total combustion air flow enters the furnace through the burners and overfire air ports on those occasions when overfire air is used. The unit is quite flexible and can accept both older style turbulent burners, such as FWEC's single register intervane design, and modern low NOx designs.

Initial shakedown and characterizational work has been done with FWEC's Controlled Flow/Split-Flame burner, Figure 6. This burner is a second generation low NOx design which achieves NOx levels about 50-60% below those of pre-New Source Performance Standard turbulent designs. Since a substantial body of developmental and field data (from industrial and utility boiler operation) already exist, the performance of the low NOx burner/CETF arrangement can be readily compared to the background inventory data. After sufficient baseline data is obtained with the CF/SF burner on several fuels, these burners will be removed and advanced experimental designs installed for evaluation.

Process Analysis and Control Equipment

The devices used for process measurements and control are listed in Table 4. The signals from those devices used for control/alarm purposes are fed to a Forney AFS-1000 microprocessor-based, integrated burner management and combustion control system. Through the AFS-1000 system, the various pieces of equipment and portions of the process are controlled. All the start-stop switches for major equipment, equipment status indicators, manual-automatic control stations for significant operating parameters, and analog indicators of some significant data are contained in the AFS-1000 control console. In addition, the AFS-1000 system indicates alarm conditions when preset values of operating parameters are exceeded, and the system initiates equipment trips when preset trip conditions are exceeded.

In the Fall of 1986, during the installation of the horizontal burners, a Gould automatic data acquisition system, coupled to an IBM industrial PC/AT, was added to the control equipment. With the appropriate software, this system allows all measured data points to be monitored, recorded at the appropriate sampling frequency and reported as trended or rolling average data.

An IMB PC/AT with identical software is located in FWEC's engineering offices and connected via modem to both the Gould DAS and PC/AT in the control room. By accessing the former, personnel in the engineering office can monitor the testing on-line without interfering with the operation. By accessing the control room PC/AT, engineering and management personnel can participate interactively with the testing.

Furnace Exit Gas Temperature is determined analytically by evaluating the convection pass heat balance. Direct measurements are also made with fixed thermocouple grids and HVT probes.

Since all measured data is input directly to the computer and averaged over the test interval, all flows, temperatures and duties are output in real time. Therefore it is possible to evaluate the effects of new burner designs, different fuels or furnace sorbent injection for SO_2 control on unit operations without performing off-line calculations which can cause significant program delays. The CETF is used to its maximum extent and test program delays are minimized.

Figure 7 is a schematic representation of the information and control paths available with this arrangement.

Of major importance to steam generator designers are the Furnace Exit Gas Temperature, furnace absorption pattern and relative absorption duties between the various sections of the unit. In order to maximize information on these parameters the CETF has been designed, as shown in Figure 8, with means of independently measuring:

- Furnace duty
- Economizer duty
- Waterwall absorption

These values are obtained by performing calorimetric measurements on each section by directly monitoring water flow and inlet and outlet temperatures. For example, all the heat absorbed by the furnace walls generates steam which exits the unit via the steam drum. The furnace feedwater supply acts solely as make-up water. Therefore, by measuring the feedwater flow and temperature and the drum temperature the average furnace absorption is obtained.

Gaseous Analysis Equipment

Effluent gas from the furnace is analyzed on a continuous basis--by in-situ analysis (analyzer component inserted into the gas stream) and by extracting gas samples, conditioning them, and transporting them to analyzers remotely located from the main gas stream. The continuous analyzers in use at the CETF are listed in Table 5.

Each of these analyzers is calibrated at the outset of a test day with zero-grade nitrogen and a certified (+2 percent) calibration gas. Following completion of the testing, each analyzer is recalibrated using the same calibration gases; results are recorded.

With the exception of the Westinghouse O_2 analyzer (an in-situ device), the continuous analyzers measure an extracted sample. All instruments are supplied by a single sampling system (Figure 9) with the exception of the hydrocarbon analyzer, which has its own system. This system extracts gas samples from the duct downstream of the air heater and upstream of the baghouse, through a stainless steel probe with a sintered stainless steel filter on its tip. The sample is then drawn into a condensate trap immersed in an ice-water bath for removal of moisture. The sample continues through the condensate trap via Polyflo plastic tubing (manufactured by Imperial Eastman), a high-efficency particulate filter--99.999 percent removal of particles (manufactured by Balston), a refrigeration dryer, and the sample pump. From the pump, the sample is transported through approximately 30 m (100 ft) of Polyflo tubing to a manifold that distributes it to the instruments. In addition to the aforementioned conditioning devices, the SO_2 and CO analyzers also utilize a permeation dryer for additional sample drying. The total sample flow is about 157 cm^3/S (20 sft^3/h). Each of the five analyzers in the system requires a 12 cm^3/s (1.5 sft^3/h) flow rate; the remainder [about 94 cm^3/s (12 sft^3/h)] is vented to atmosphere. The purpose of drawing a sample at twice the required rate is to reduce overall analyzer response time.

Several sampling systems for the hydrocarbon flame ionization detector (FID) have been used thus far in the test program. The initial system utilized a system identical to that used for the other continuous extraction analyzers. Because it appeared to introduce errors in the form of trace hydrocarbon contamination from the Polyflo tubing, the tubing was replaced with refrigeration-grade cooper tubing upon the recommendation of the instrument manufacturer. This change eliminated the contamination problem. Other sampling systems were tested to determine whether hydrocarbons within the effluent gas samples were being lost to condensation or solution in water. No difference in hydrocarbon emissions was found with these other sampling systems, indicating no loss of hydrocarbons to condensation or dissolution. This was confirmed during the petroleum coke test program with chromatographic analysis of extracted gas samples by an independent laboratory.

During a portion of the test program, a device was incorporated in the hydrocarbon sampling system to allow differentiation between methane and non-methane hydrocarbons. This device, known as a non-methane cutter (NMC), catalytically oxidizes non-methane hydrocarbons, making them undetectable to the FID.

TEST RESULTS

Each day of testing, the facility is heated via natural-gas igniters fired from the burner deck [rated at approximately 16 x 10^6 Btu/h]. When secondary air, primary air, and air leaving the mill reach operating temperatures, fuel is fed to the mill and the unit is gradually brought up to full load. This process requires about 3 hours. After full load is achieved, natural-gas flow is removed.

Testing has been performed with both arch-fired and horizontally-fired configurations. The former involved petroleum coke using the standard FWEC cyclone-separator burner, followed by a test series with both pet-coke and bituminous coal, utilizing low NOx modifications to the standard burner. Although effective for both fuel types, these low NOx modifications were developed primarily for pet-coke and were not optimized for bituminous coal.

Conversion to horizontal firing and upgrading of the control/data system concluded in late November 1986. Start-up and shakedown commenced in early December. A short characterizational test series was run with the standard Controlled Flow/Split-flame low NOx burner. The same bituminous coal used for the arch tests was also fired with the low NOx burners. Due to a contractual commitment with a utility customer, requiring the initiation of an extensive test program immediately upon conclusion of the shakedown, only sufficient testing was done to confirm the burner's performance and furnace performance.

The following discussion outlines each test series and its primary results.

PETROLEUM COKE TESTS

During the petroleum coke evaluation numerous tests were performed to determine emissions and the possible effect on flame stability of varying combustion system parameters and unit operating conditions. The most significant results are discussed below:

Hydrocarbon Analysis

Early test results using the FID indicated hydrocarbon levels varying from 1.5 to 20 ppm. Most readings were between 1.5 and 4.0 ppm, with considerable drift. Following modification of the sampling system as discussed above, emissions became stable in the 0.5 to 1.8 ppm range. Several significant observations were made about hydrocarbon measurements:

o Hydrocarbon emissions were higher with higher proportions of natural gas when gas and coke were fired simultaneously and highest with natural gas alone

- Hydrocarbon emissions were lowest (in the 1.0 ppm range) when petroleum coke was fired with no support fuel
- Ambient air levels of hydrocarbons were higher than emissions resulting from coke combustion (by an order of magnitude)
- When Polyflo tubing was replaced with unheated copper refrigeration tubing, heat-traced stainless steel tubing, or unheated stainless steel tubing (with or without condensate traps or moisture-removal devices), there was no difference in the measured hydrocarbon level.

Since the heat tracing of the sample tubing and the elimination of the condensation of moisture had no effect on the hydrocarbon emission level, it is very doubtful that any condensible or soluble hydrocarbons were present. This is not surprising, since the vapor pressures of even heavy hydrocarbons and the solubility of most hydrocarbons are such that any small amount passing through the trap (not condensing) would cause significantly higher readings than were reported (by several orders of magnitude). This conclusion was confirmed by laboratory tests for condensible and soluble hydrocarbons, performed during one of the test runs.

Several gas samples were extracted throughout the test program; placed in stainless steel bombs, glass bombs, or Tedlar plastic bags; and analyzed by analytical laboratories--primarily for hydrocarbons by gas chromatography. One sample was extracted for determination of condensible hydrocarbons (these results showed a trace amount was present). Several things are apparent from the results of these analyses:

- No hydrocarbons heavier than methane were detected.
- Use of the non-methane cutter in conjunction with the FID indicated the absence of significant non-methane hydrocarbons--essentially confirmed by most of the chromatographic results.
- Within the limits of demonstrated operation, hydrocarbon emissions appear to be independent of combustion conditions over the normal range of equipment operation.

Oxides of Nitrogen - Standard Arch-Fired Burners

Emissions of oxides of nitrogen (NOx), measured while support fuel was in use, were quite low. NOx emissions could be raised or lowered by manipulation of the burner controls and the secondary air distribution. Excess air had the most predominant effect on NOx, however.

During the early portion of the test program, a small quantity of natural gas was used as a stablizing support fuel (less than 5% total heat input).

With support fuel in use, NOx emissions were generally lower than without. This decrease may have been the result of a reducing zone being formed at the base of the coke flame by natural gas introduced at this point, affecting NOx formation. When support fuel was removed, NOx emissions increased slightly in most cases. This increase was probably partly because of the aforementioned natural-gas effect and partly the changes in flame configurations.

During the majority of the program the pet-coke was fired unsupported. Stable combustion was achieved by adjustment of burner controls. Although NOx could be raised to over 0.7 lb/million Btu with settings of these controls, the typical NOx levels was 0.5 - 0.6 lb/million Btu; corresponding to levels measured on industrial boilers.

Figure 10 summarizes the typical NOx variation with overfire air, which is a supplementary, but very effective means of significantly reducing the emissions: to 0.25 lb/million Btu (approximately 55% reduction). It should be noted that the CETF, in arch configuration, is a scale model of the 150 MW unit shown in Figure 1, which is not equipped with overfire air ports. However, it does have an NOx guarantee 0.7 lb/million Btu.

At full load the NOx emissions from the field unit are approximately 0.55 lb/million Btu, which compares quite favorably with the 0% overfire air CETF data of Figure 10. Clearly, the standard arch-fired unit and its combustion system represent an inherently low NOx system: without overfire.

However, in expectation of future reductions in NOx limits. FWEC tested a low NOx modification of the standard cyclone-separator burner. These results are also shown on Figure 10. The 0% overfire air case yields NOx reduced from 0.55 to 0.4 lb/million Btu due entirely to the burner modifications. With 100% overfire air NOx is reduced to about 0.13 lb/million Btu (67.5% from 0.4). The low NOx burner modifications have enhanced the effect of overfire air.

These results are particularly significant in light of the petroleum coke analysis of Table 1: Volatile Matter 11.5%, nitrogen about 1.6%.

During most of these tests excess O_2 was in the range of 2.5-3.5% with CO generally 35 - 75 ppm. Although CO could be increased to several hundred ppm when O_2 was reduced below 2.5%.

Sulfur Dioxide

Sulfur dioxide emissions are a function of fuel sulfur and excess air level, and this proved to be the case while firing petroleum coke with approximately 4 wt% sulfur. Sulfur dioxide emissions were approximately 3150 ppm at 4.2 percent oxygen and fluctuated with excess air changes (down for an increase in air, up for decrease in air). Sulfur dioxide emission control by sodium bicarbonate injection was quite effective, with removal efficiencies in excess of 70 percent easily achieved.

Bituminous Coal Tests

All the bituminous coal, arch-fired testing was performed with low NOx modifications to the standard pet-coke burner: no attempt was made to optimize the burner design for bituminous coal. However, as shown in Figure 11, NOx emissions can be reduced to about 0.1 lb/million Btu with overfire air, from about 0.42. The NOx reduction effect was slightly greater with bituminous coal than with the pet-coke.

Approximately 30 tests were performed to evaluate load, excess air and combustion system parameters. The data of Figure 11 are representative of good combustion conditions at full load. Excess O_2 is 3 1/2 - 4 1/2% and CO is 50-150 ppm.

There is some limited field data from utility boilers firing bituminous coal on an arch with a roughly similar combustion system. Although the thermal environments are different (the field units have cooler furnaces) there is good correlation with the CETF.

HORIZONTAL FIRING - BITUMINOUS COAL

Subsequent to the furnace conversion to horizontal firing with two burners, a short characterizational test program was performed. Since there already exists an extensive body of field data (from industrial boiler's) and developmental data (from both an industrial unit used by FWEC for developmental purposes and another Test facility) the CETF's data could be rapidly checked for reliability. Figure 12 summarizes this data. FWEC's inventory field data for similar fuels and this burner size show NOx levels ranging from 0.3 - 0.4 lb/million Btu without overfire air. The CETF results show excellent agreement with this earlier data.

For comparison, Figure 12 also contains the overfire air curve for the low NOx arch fired bituminous coal results presented in the previous section.

As with the arch-fired data O_2 and CO are in the 3 - 4% and 50 - 150 ppm ranges, respectively.

In January 1987 a test program funded by a utility customer was begun. The program involves comparative testing between FWEC's pre-NSPS turbulent intervane burner and the CF/SF low NOx burner utilizing the utility's coal. After the intervane burners were installed the CETF shakedown was accomplished with the bituminous coal as used in the test series discussed above. Both furnace performance and emission data were taken. Figure 13 summarizes the NOx data and compares it to the low NOx burner data of Figure 12. The 60% NOx reduction is similar to results obtained in field practice.

To illustrate some field results, Figure 14 compares the CETF intervane and low NOx burner data with corresponding data from a 650 MW steam generator which was retrofitted with low NOx burners in February 1986. The bituminous coal fired on the CETF is from this utility station. The results correlate quite satisfactorily.

A more detailed discussion of this field retrofit is contained in a comparison paper presented at this conference ("Industrial and Utility Boiler NOx Control Update").

Performance Results

There are several burner/furnace parameters which are of interest when evaluating the performance of a low NOx system for use with either new steam generators or as retrofits to older units. Among these are:

- Burner Zone Liberation Rate: A measure of the relative heat input per unit equivalent heat transfer surface available in the burner zone. BZLR usually calculated as Btu/hr-ft^2. The higher this value the hotter the furnace and the greater the amount of NOx generated.

- Furnace Exit Gas Temperature: The FEGT can be reviewed as being the thermal fulcrum between the furnace and convection pass. Generally the smaller the furnace, for a given thermal load, the higher will be the FEGT. This parameter increases with load, slag coverage on walls and with increased flame lengths. Since a steam generator's convection pass is designed to utilize the available heat head between the furnace exit and the flue, large changes in

FEGT caused by equipment modifications can adversely affect the unit's ability to control steam temperatures, as well as its efficiency.

- Burner Pressure Drop: The resistance across the burner will determine the size of the forced draft (FD) fan. High differentials will result in large fans and high parasitic power consumption. Therefore, burner pressure drop should be no higher than necessary to maintain proper burner aerodynamics.

The following discussion outlines Foster Wheeler's philosophy for each of the above design considerations along with relevant test results from the CETF:

- BZLR:
  Figure 15 is a plot of BZLR which compares NOx variations for pre-NSPS burners with the Controlled Flow/Split-flame burner. Data from both industrial and utility steam generators are represented, as is the CETF. The full load BZLR for the CETF is about 230,000 Btu/hr-ft^2, higher than most industrial units and at the bottom of the utility range. Due to surface-volume relationships it is not practical to increase BZLR beyond this value. The curves shown in Figure 15 were developed from industrial and utility steam generators, each point represents full load operation for the particular steam generator from which the data was taken. The CETF's turbulent and low NOx burner data are shown and match their respective curves quite well, thereby confirming the CETF's design philosophy.

- FEGT:
  The CETF's FEGT was set at a value corresponding to that of most industrial and many utility steam generators: 2000 - 2200°F. The relatively short furnace with reduced upper furnace cross-section makes the thermal system very sensitive to changes in flame and lower furnace conditions. In particular, long flames will show up immediately as an increased FEGT. Consequently, FWEC has a sensitive tool for evaluating the commercial viability of new burner designs: short flames which do not increase FEGT are preferable for commercial steam generator operation. The CETF testing summarized by the turbulent and low NOx burner data points on Figure 15 also included FEGT measurements, and detailed flame observations. There were no significant changes in either indications between the two burner designs: in both cases full load flames were 4 - 6 ft. off the back wall and FEGT remained within the same narrow temperature band. It should be noted that the low NOx burner has extreme flexibility and can produce almost any flame shape including the long, narrow flame which is undesirable from FWEC's point of view).

- Burner Pressure Drop:
  Some low NOx burner designs require high pressure drop to produce low NOx emissions. However, FWEC's philosophy has been to design burners which produce low NOx while operating with Burner Pressure Drops no greater than obtained historically with turbulent burners: 2 - 4" W.C. The CF/SF burner achieves the low NOx levels presented above while operating within this pressure drop range. On the CETF, NOx emissions, with bituminous coal, are about 0.35 lb/million Btu with burner pressure drop less than 2.0" W.C. (without overfire air).

SUMMARY

Initial testing on the CETF has emphasized characterizations of FWEC's standard arch-firing and low NOx horizontally fired configurations. Although only relatively minor low NOx modifications were made to the former, NOx emissions were reduced to about 0.13 lb/million Btu with overfire air. In the latter case, commercial Controlled-Flow/Split-flame low NOx burners were evaluated without and with overfire air: NOx emissions were below 0.4 and 0.15 lb/million Btu respectively.

Extensive testing was also done to quantify hydrocarbon emissions. Emissions are generally less than 1.0 ppm for both petroleum coke and bituminous coal under various operating methods.

Comparison of CETF data with field units, arch-fired with petroleum coke and horizontally-fired with bituminous coal, results in excellent thermal and emissions correlation. In particular, the furnace has been characterized with a pair of turbulent intervane burners and a pair of FWEC's commercial low NOx burners. Under this well-monitored test program there were no observations of flame impingement on the furnace rear-wall nor of flames extending vertically into the screen tubes. These results support observations made in the field on both industrial and utility steam generators.

Plans for the near term include test programs for commercial customers, additional characterization of the existing low NOx burners with more coals, sorbent injection for SO_2 capture and testing of new in-house low NOx burner designs.

TABLE 1: PETROLEUM COKE ANALYSIS

	As Received	Dry
Proximate Analysis (wt%)		
Fixed Carbon	76.47	85.51
Volatile	11.54	12.91
Ash	1.41	1.58
Moisture	10.58	---
Total	100.00	100.00
FC/VM	6.63	
Ultimate Analysis (wt%)		
Carbon	76.88	84.97
Hydrogen	3.28	3.67
Oxygen	2.34	2.63
Nitrogen	1.57	1.75
Sulfur	3.94	4.40
Ash	1.41	1.58
Moisture	10.58	---
Total	100.00	100.00
HHV, Btu/lb	13,562	15,167

TABLE 2: BITUMINOUS COAL ANALYSIS

	As Received	Dry
Proximate Analysis (wt%)		
Fixed Carbon	50.35	52.02
Volatile Matter	34.74	35.90
Ash	11.69	12.08
H_2O	3.22	--
Total	100.00	100.00
FC/VM	1.45	
Ultimate Analysis		
Carbon	69.98	71.31
Hydrogen	4.97	5.13
Oxygen	5.44	5.62
Nitrogen	1.33	1.38
Sulfur	3.37	3.48
Ash	11.69	12.08
H_2O	3.22	
	100.00	100.00
HHV/Btu/lb	12,700	

TABLE 3: TYPICAL CETF OPERATING CONDITIONS

Secondary Airflow (lb/h)	25,000 to 60,000
Primary Airflow (lb/h)	4,000 to 12,000
Fuel Flow (lb/h)	1,600 to 10,000
Secondary Air Temperature (°F)	450 to 650
Primary Air/Fuel Temperature--Mill Exit (°F)	140 to 210
Furnace Exit Gas Temperature (°F)	1600 - 2200
Flue Gas Temperature--Entering Baghouse (°F)	300 to 385
Cooling Water In (°F)	40 to 100
Cooling Water Out (°F)	150 to 180
Flue Gas, O_2 (%)	1.5 to 6.0

TABLE 5: CETF ANALYZERS

Gas	Analysis Method/Principle	Instrument Manufacturer
O_2 (WFT)	Zirconium Dioxide	Westinghouse
O_2 (DFG)	Paramagnetic	Beckman
CO_2	Nondispersive Infra Red (NDIR)	Beckman
CO	Nondispersive Infra Red (NDIR)	Beckman
SO_2	Nondispersive Infra Red (NDIR)	Beckman
C_xH_y	Flame Ionization Detector (FID)	Beckman
NOx	Chemiluminescense	Thermo Electron

FOSTER WHEELER STEAM GENERATOR

FOR

APPLIED ENERGY SERVICES INCORPORATED
DEEPWATER COGENERATION PROJECT

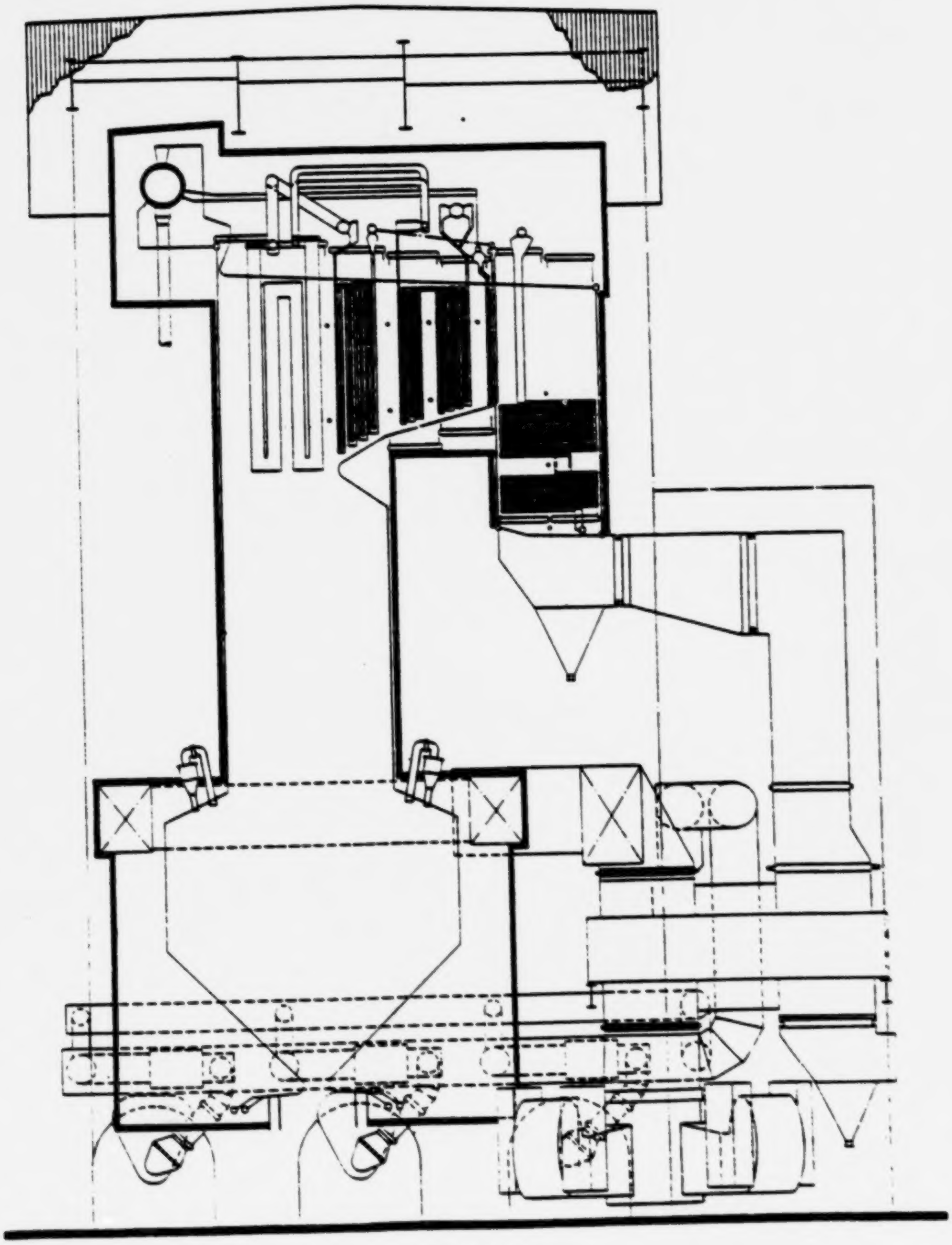


FIGURE 1

CETF : ARCH-FIRED

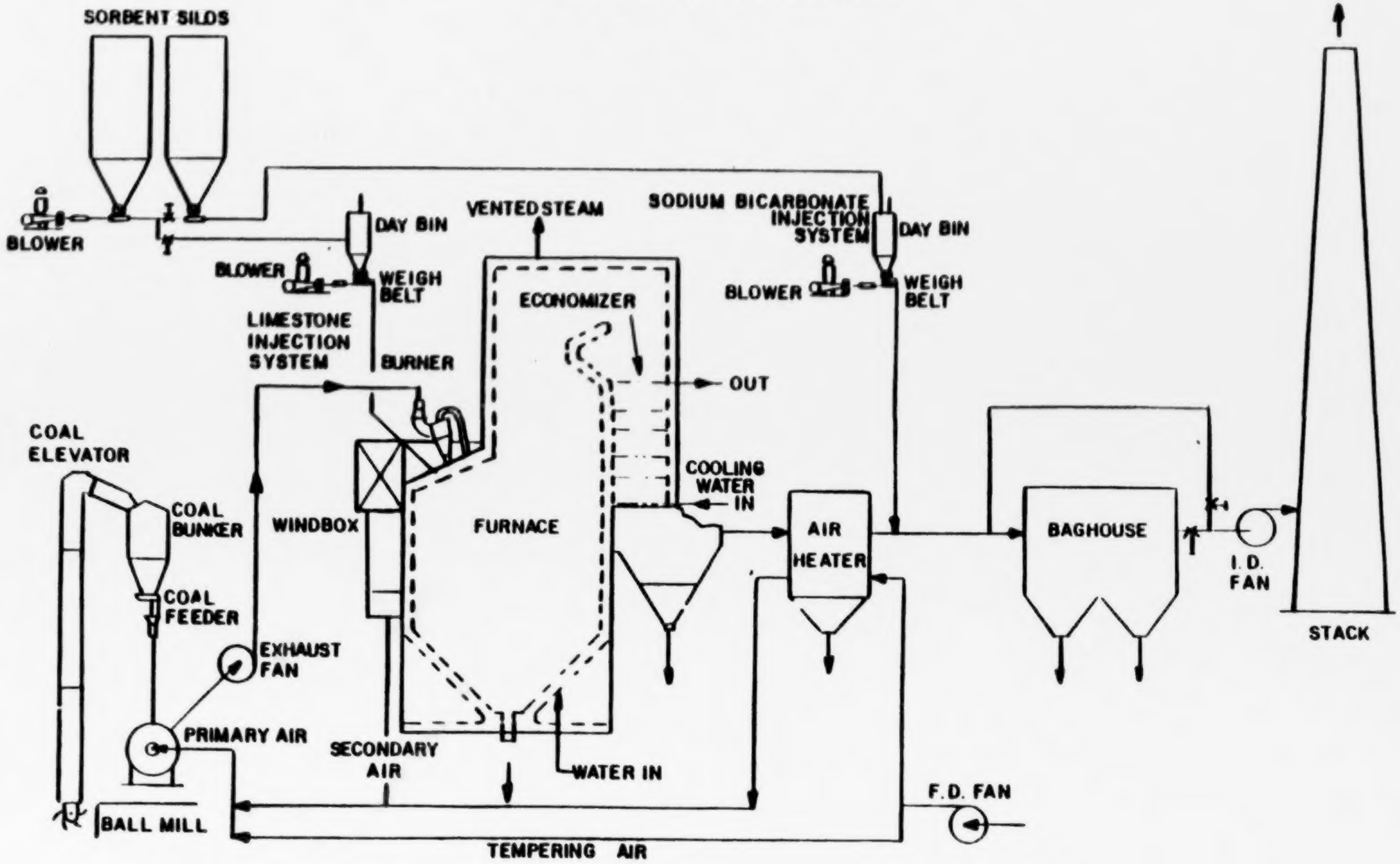

SORBENT SILOS
BLOWER
DAY BIN
BLOWER
WEIGH BELT
LIMESTONE INJECTION SYSTEM
BURNER
VENTED STEAM
ECONOMIZER
OUT
SODIUM BICARBONATE INJECTION SYSTEM
DAY BIN
BLOWER
WEIGH BELT
COAL ELEVATOR
COAL BUNKER
COAL FEEDER
WINDBOX
FURNACE
COOLING WATER IN
AIR HEATER
BAGHOUSE
I. D. FAN
STACK
EXHAUST FAN
PRIMARY AIR
SECONDARY AIR
WATER IN
BALL MILL
TEMPERING AIR
F.D. FAN

FIGURE 2

CETF : HORIZONTAL-FIRED

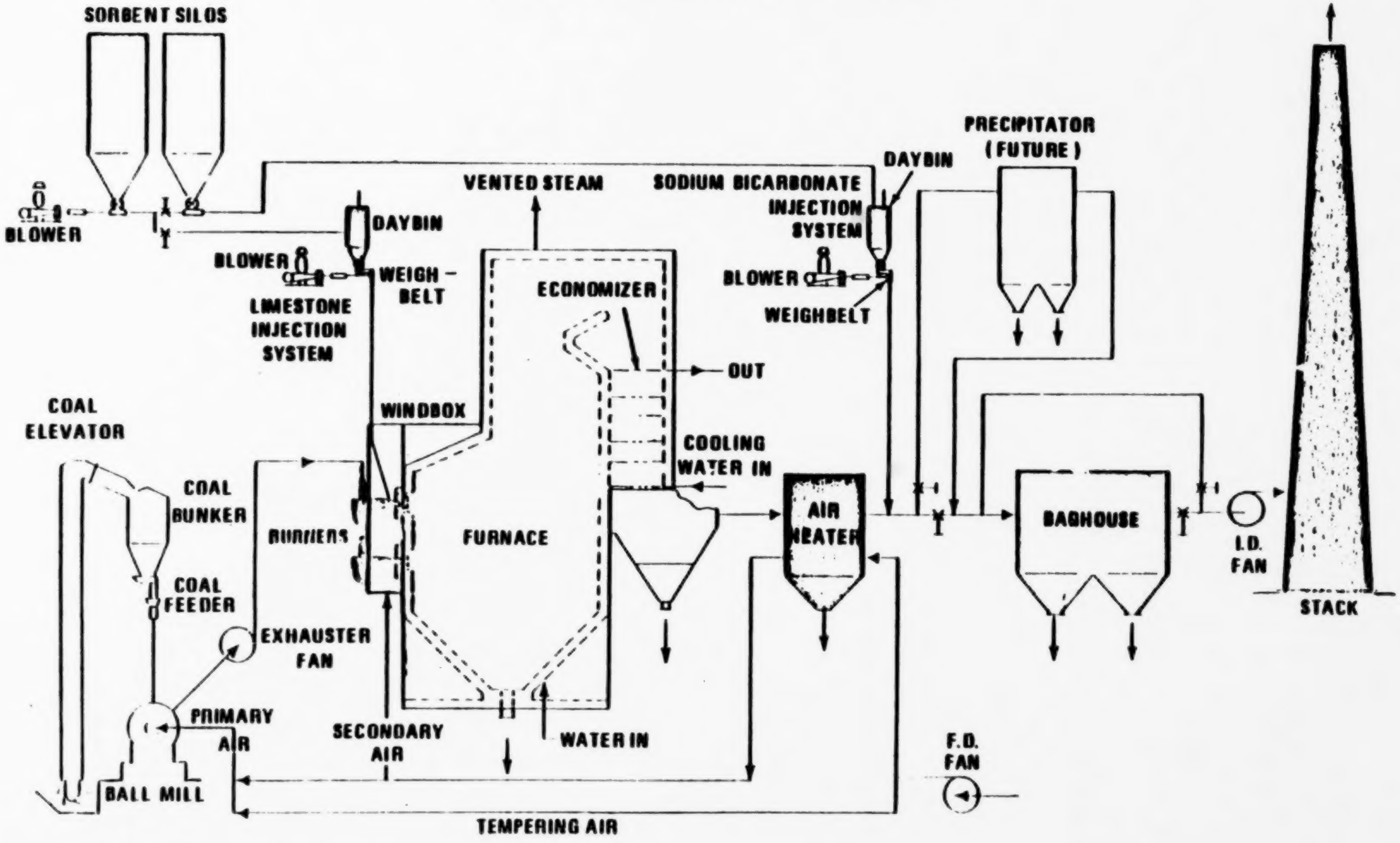

SORBENT SILOS
BLOWER
DAYBIN
BLOWER
WEIGH - BELT
LIMESTONE INJECTION SYSTEM
VENTED STEAM
ECONOMIZER
OUT
SODIUM BICARBONATE INJECTION SYSTEM
DAYBIN
BLOWER
WEIGHBELT
PRECIPITATOR (FUTURE)
COAL ELEVATOR
WINDBOX
COAL BUNKER
BURNERS
FURNACE
COOLING WATER IN
AIR HEATER
BAGHOUSE
I.D. FAN
STACK
COAL FEEDER
EXHAUSTER FAN
PRIMARY AIR
SECONDARY AIR
WATER IN
F.D. FAN
BALL MILL
TEMPERING AIR

FIGURE 3

CETF : PLAN VIEW

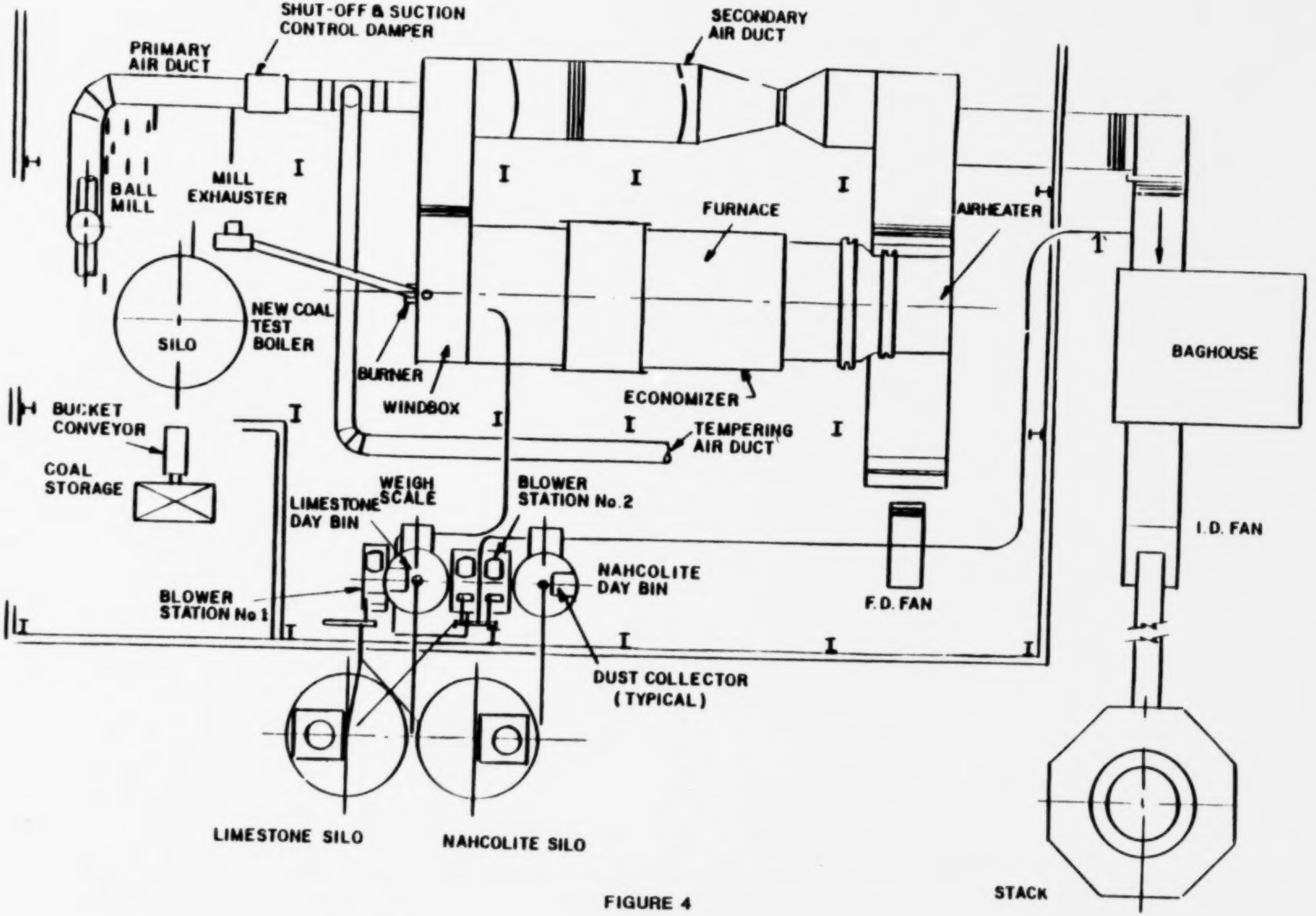

SHUT-OFF & SUCTION CONTROL DAMPER
SECONDARY AIR DUCT
PRIMARY AIR DUCT
BALL MILL
MILL EXHAUSTER
FURNACE
AIRHEATER
NEW COAL TEST BOILER
SILO
BURNER
WINDBOX
ECONOMIZER
BAGHOUSE
BUCKET CONVEYOR
COAL STORAGE
TEMPERING AIR DUCT
WEIGH SCALE
LIMESTONE DAY BIN
BLOWER STATION No.2
NAHCOLITE DAY BIN
BLOWER STATION No 1
I.D. FAN
F.D. FAN
DUST COLLECTOR (TYPICAL)
LIMESTONE SILO
NAHCOLITE SILO
STACK

FIGURE 4

ARCH-FIRED AIR DISTRIBUTION SYSTEM

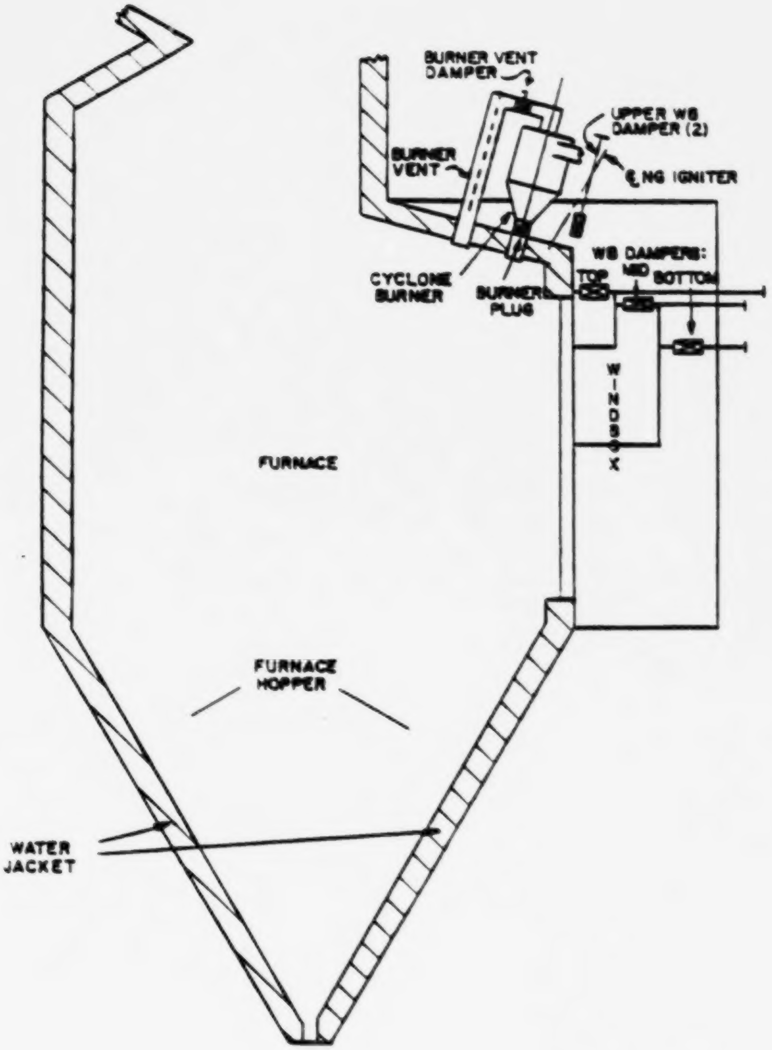
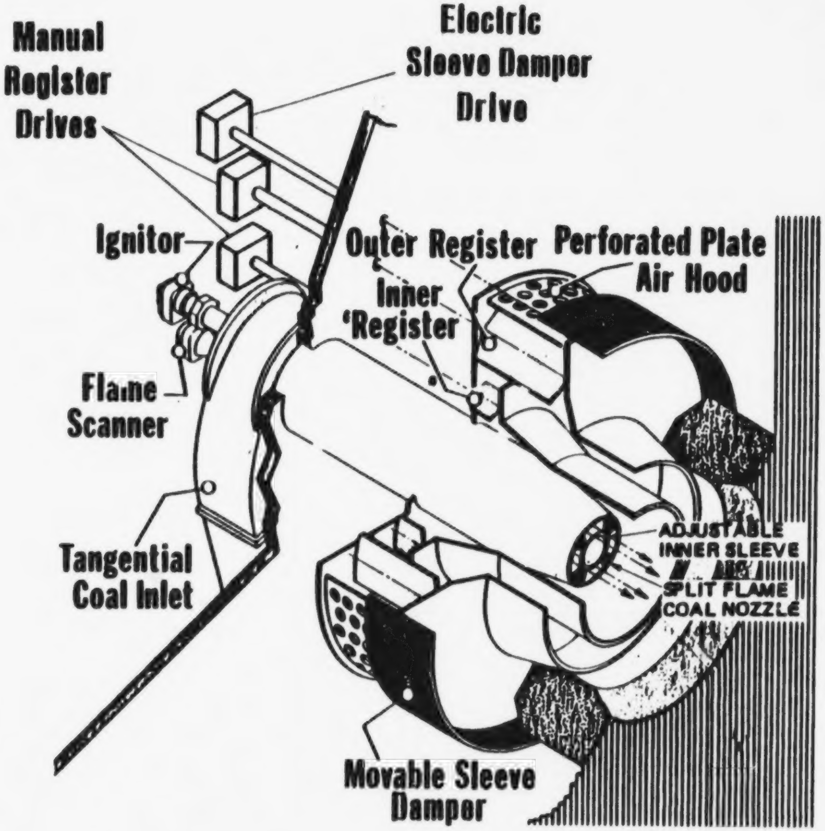

BURNER VENT DAMPER
UPPER WB DAMPER (2)
BURNER VENT
℄ NG IGNITER
WB DAMPERS:
TOP
MID
BOTTOM
CYCLONE BURNER
BURNER PLUG
WINDBOX
FURNACE
FURNACE HOPPER
WATER JACKET

FIGURE 5


Manual
Register
Drives
Electric
Sleeve Damper
Drive
Ignitor
Outer Register
Perforated Plate
Air Hood
Inner
'Register
Flame
Scanner
Tangential
Coal Inlet
ADJUSTABLE
INNER SLEEVE
SPLIT FLAME
COAL NOZZLE
Movable Sleeve
Damper

CONTROLLED FLOW SPLIT FLAME BURNER

FIGURE 6

INTERACTIVE DATA ACQUISITION
AND
CONTROL SYSTEM

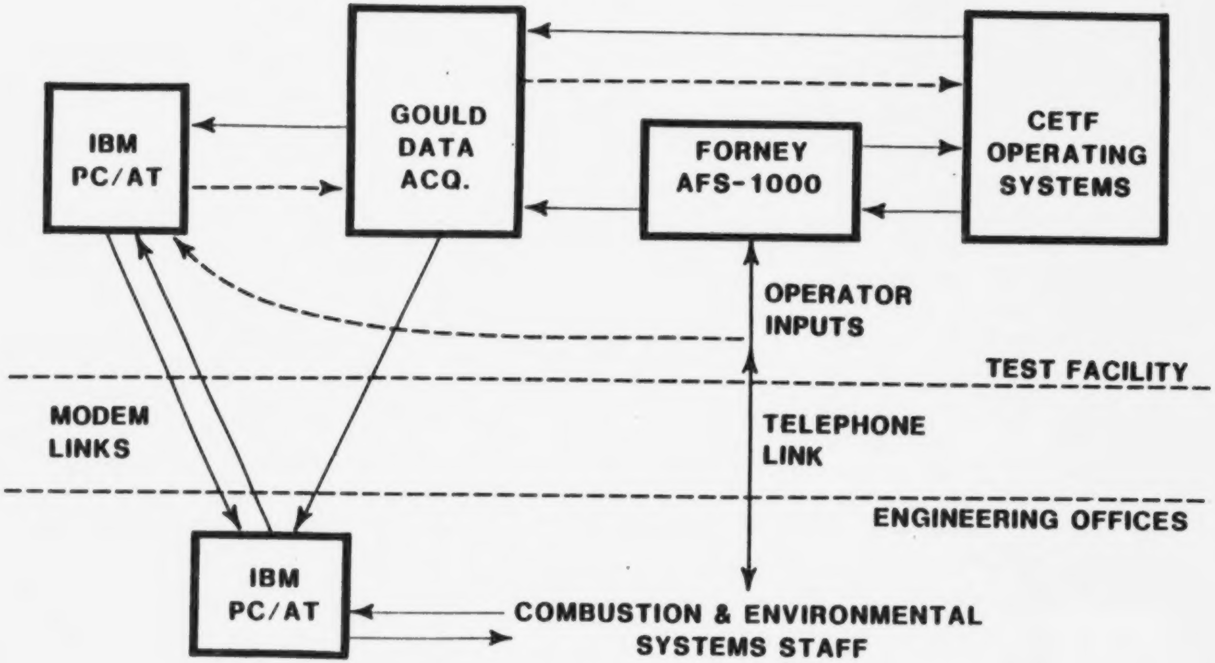

IBM
PC/AT
GOULD
DATA
ACQ.
FORNEY
AFS-1000
CETF
OPERATING
SYSTEMS
OPERATOR
INPUTS
TEST FACILITY
MODEM
LINKS
TELEPHONE
LINK
ENGINEERING OFFICES
IBM
PC/AT
COMBUSTION & ENVIRONMENTAL
SYSTEMS STAFF

FIGURE 7

CETF
HEAT TRANSFER SURFACE ARRANGEMENT

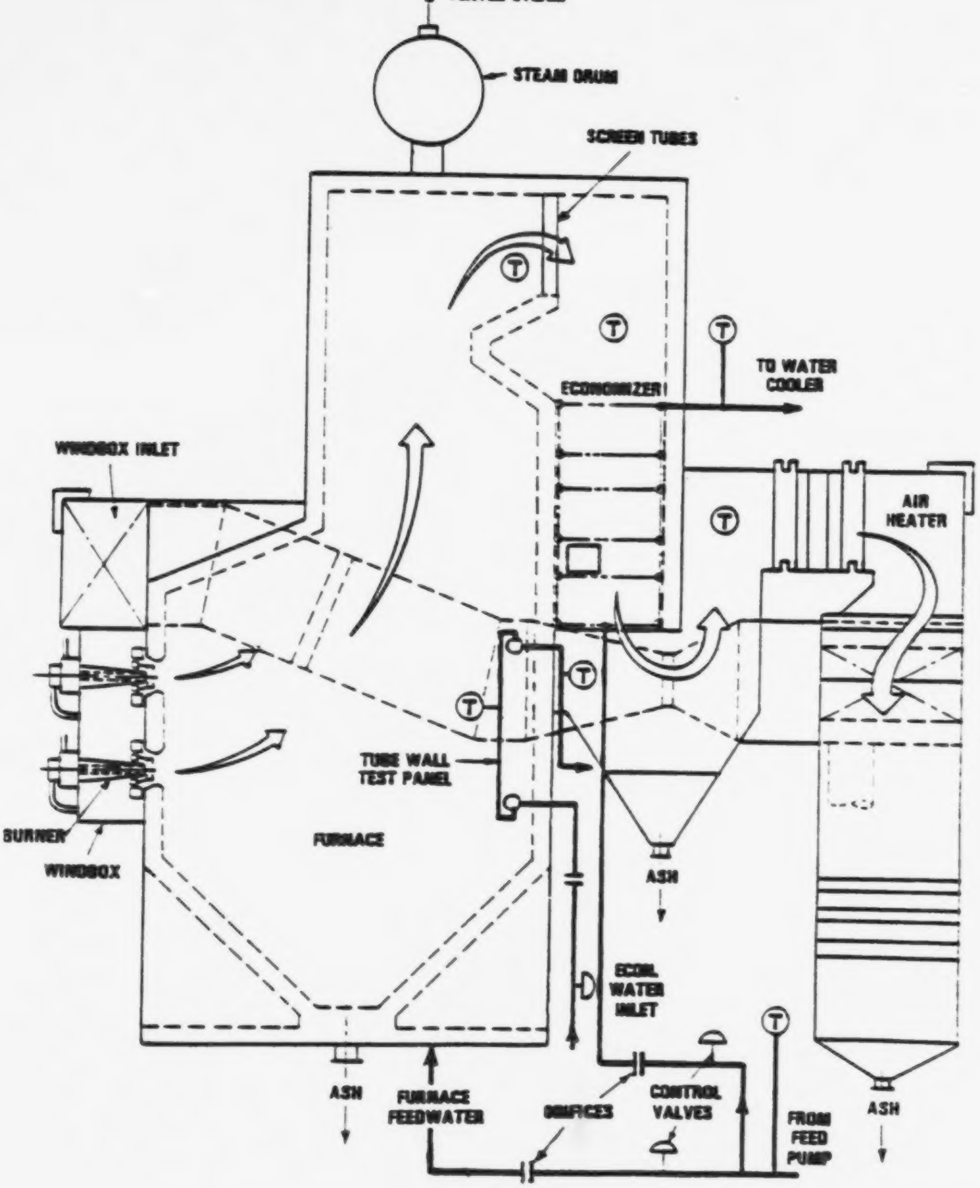

VENTED STEAM
STEAM DRUM
SCREEN TUBES
T
T
T
TO WATER COOLER
ECONOMIZER
WINDBOX INLET
T
AIR HEATER
T
T
TUBE WALL TEST PANEL
BURNER
WINDBOX
FURNACE
ASH
ECON. WATER INLET
T
ASH
FURNACE FEEDWATER
ORIFICES
CONTROL VALVES
FROM FEED PUMP
ASH

FIGURE 8

CONTINUOUS ANALYZER
EXTRACTIVE SAMPLING SYSTEM

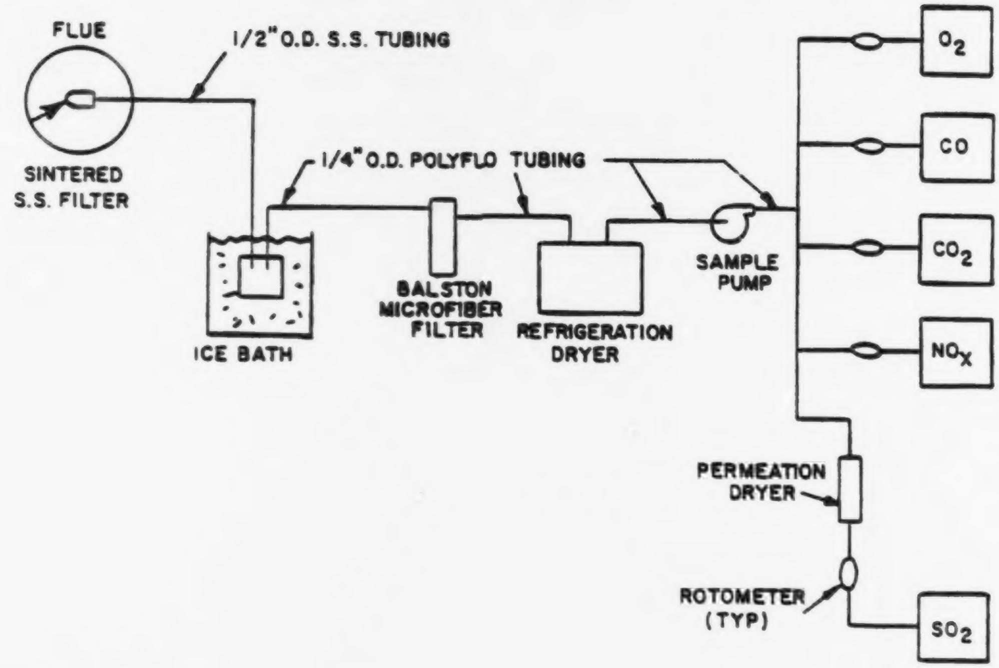

FLUE
1/2" O.D. S.S. TUBING
SINTERED S.S. FILTER
1/4" O.D. POLYFLO TUBING
ICE BATH
BALSTON MICROFIBER FILTER
REFRIGERATION DRYER
SAMPLE PUMP
O_2
CO
CO_2
NO_x
PERMEATION DRYER
ROTOMETER (TYP)
SO_2

FIGURE 9

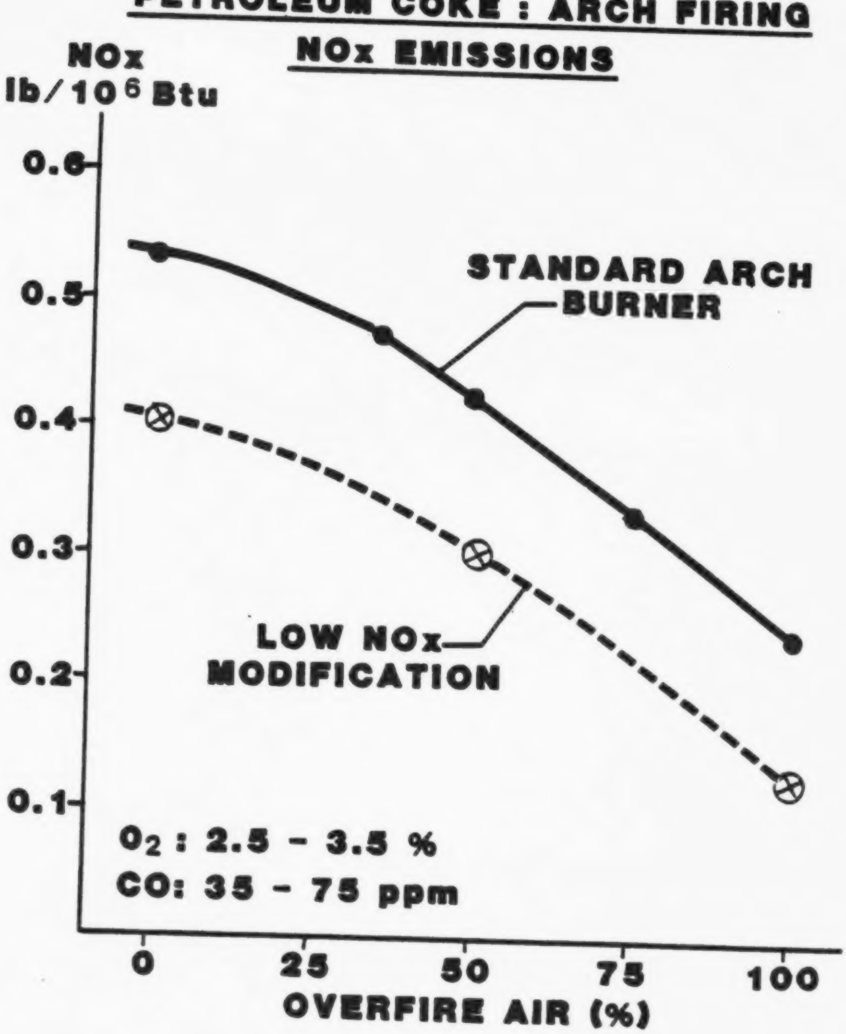

PETROLEUM COKE : ARCH FIRING
NOx EMISSIONS
NOx
lb/10⁶ Btu
0.6
0.5
0.4
0.3
0.2
0.1
STANDARD ARCH
BURNER
LOW NOx
MODIFICATION
O₂ : 2.5 - 3.5 %
CO: 35 - 75 ppm
0
25
50
75
100
OVERFIRE AIR (%)

FIGURE 10

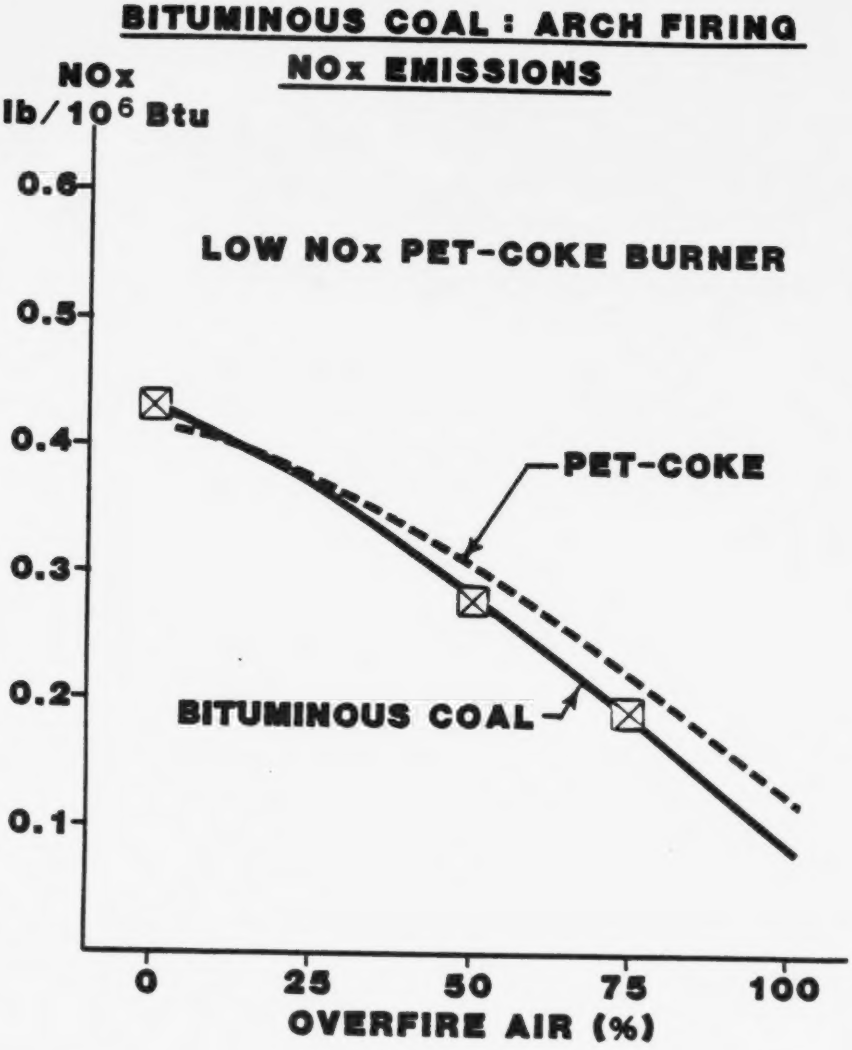

BITUMINOUS COAL : ARCH FIRING
NOx EMISSIONS
NOx
lb/10⁶ Btu
0.6
0.5
0.4
0.3
0.2
0.1
LOW NOx PET-COKE BURNER
PET-COKE
BITUMINOUS COAL
0
25
50
75
100
OVERFIRE AIR (%)

FIGURE 11

HORIZONTAL FIRING (TWO BURNERS)
BITUMINOUS COAL
NOx EMISSIONS

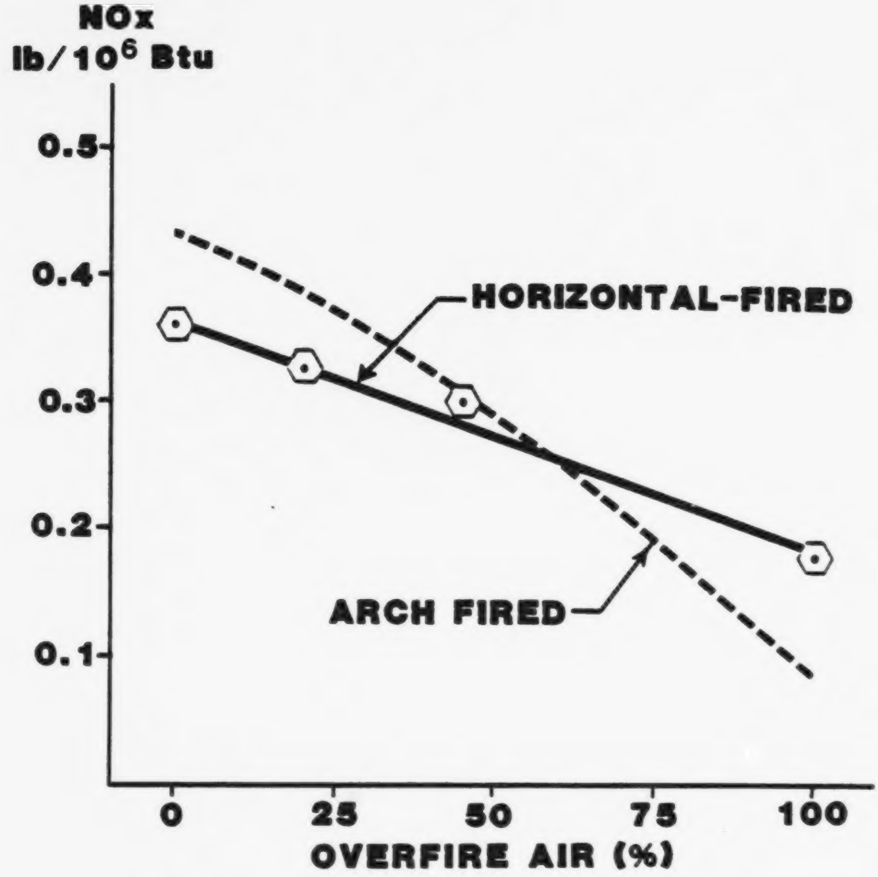


FIGURE 12

CETF BURNER COMPARISON
BITUMINOUS COAL

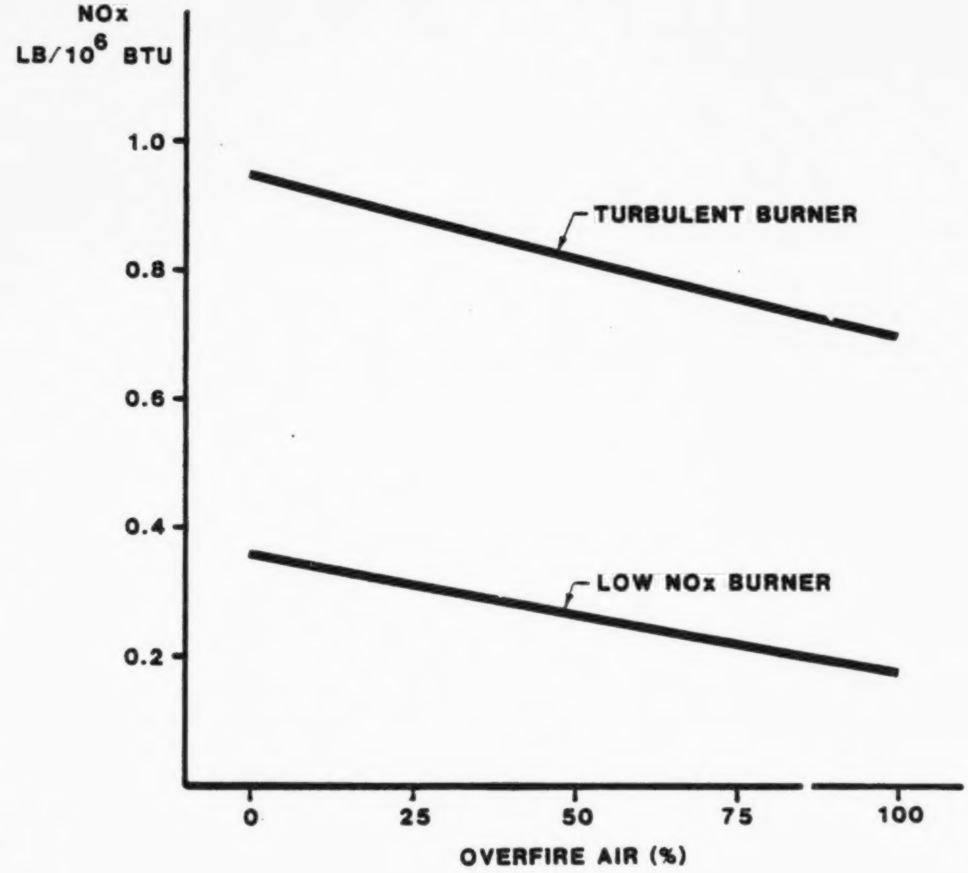


FIGURE 13

CETF vs FIELD
NOx RESULTS

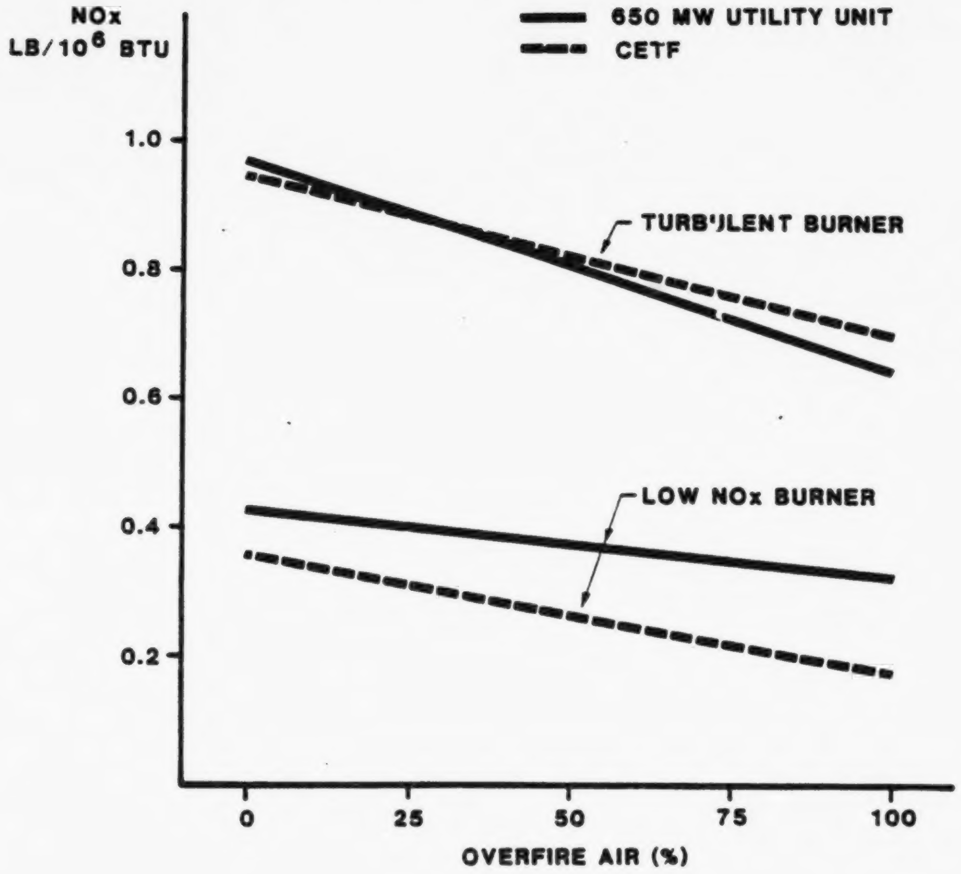


FIGURE 14

NOx REDUCTION SUMMARY

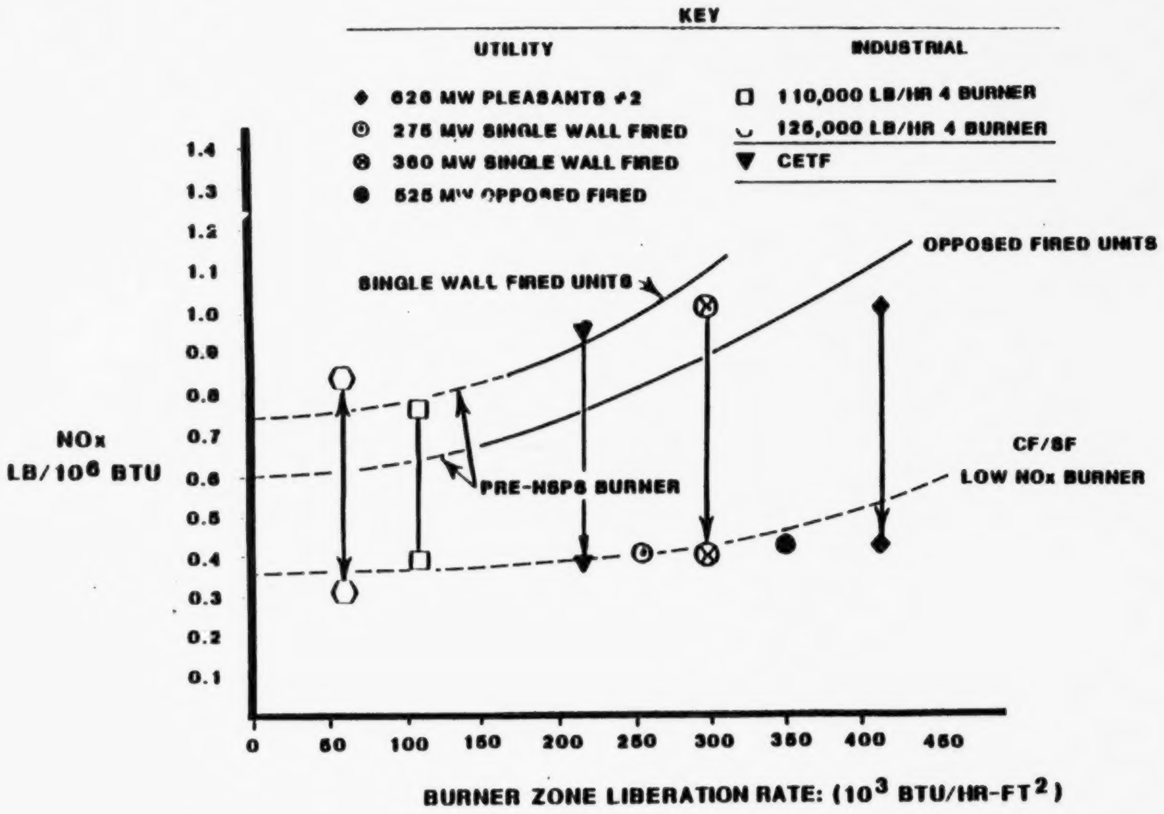


FIGURE 15

DEVELOPMENT OF OVERFIRE AIR DESIGN GUIDELINES FOR FRONT-FIRED BOILERS

Robert A. Lisauskas
Claire E. McHale
Riley Stoker Corporation

Rui Afonso
Dynatech Scientific

David Eskinazi
Electric Power Research Institute

ABSTRACT

Experimental flow model data and technical and economic studies have been used to develop design guidelines for overfire air (OFA) NO_x control systems. Conventional and novel OFA configurations were investigated in a one-twelth scale furnace model using detailed temperature and velocity maps to quantify overfire air injection and mixing. Data analyses focused on translating the flow model test results into practical designs for front-fired utility boilers. Based on the experimental results, the feasibility of retrofitting new OFA configurations on a specific utility boiler was examined.

The results for several test configurations are used to develop preliminary overfire air design guidelines for front-fired boilers. For traditional design configurations with one overfire air port located over each burner column, the best mixing occurs at an injection to furnace velocity ratio of 4 to 6. A significant improvement in upper furnace mixing can be achieved by adding wing overfire air ports and biasing the air flow and velocity from the center to the wing ports.

INTRODUCTION

Overfire air (OFA) is one commercial application of two staged combustion. It involves the diversion of combustion air to separate injection ports above the uppermost burners in the furnace. The effectiveness of OFA as a NO_x control technique on utility boilers is strongly dependent on the penetration and mixing of the second stage air with the primary combustion zone products. The Electric Power Research Institute is supporting a program to develop design and operating guidelines for retrofit and new unit overfire air systems. The goal of the first phase of this program is to develop practical guidelines for front-fired (or single wall-fired) utility boiler designs.

The performance of overfire air systems is driven by several factors. Adequate separation must be maintained between the primary and secondary combustion zones for NO_x control. This motivates the designer to locate the OFA ports as far above the burners as practical. However, efficient boiler operation requires maximizing the residence time available for carbon burnout between the OFA ports and the furnace exit. This dictates locating the OFA ports as close to the burners as practical. These conflicting constraints illustrate why a thorough understanding of OFA mixing is required to both reduce NO_x emissions and maintain combustion efficiency.

This study is based on flow modeling results and on a feasibility analysis of overfire air systems on a full scale (400 MWe) front-fired utility boiler. A 1/12th scale laboratory flow model, shown in Figure 1, was used to: 1) assess OFA mixing in a well-controlled test environment; 2) quantitatively compare the mixing achieved among various overfire air port design variations; 3) evaluate design arrangements and concepts that may be expensive or difficult to install in the field. The feasibility studies were used to introduce the realistic constraints encountered in actual retrofits into the guideline development process.

Overfire air is not a new NO_x control process. Successful field installations exist. In other cases, the NO_x reductions or carbon burnout achieved has been disappointing. This project builds upon this field experience and adds data from well-controlled studies to provide a sound technical basis for evaluating OFA mixing. Since other boiler emission control strategies such as reburning and sorbent injection are controlled by similar mixing processes, this understanding is critical to successful field demonstrations of these technologies.

FLOW MODEL

The performance of overfire air systems is dependent on both combustion and fluid dynamics. Successfully mixing overfire air with the combustion products is directly related to boiler performance parameters such as excess air requirements, carbon burnout, and NO_x formation. In the design of an overfire air system, fluid dynamic considerations are often overlooked. As a result the performance of overfire air systems on operating boilers is inconsistent. The following flow-related parameters were evaluated in the test program:

- OFA jet velocity
- OFA port size, number and location
- OFA jet swirl
- OFA velocity and flow bias between ports

Some of these parameters are not independent. For example, OFA port size and number will determine OFA jet velocity for a given degree of staging. The optimization of each is required for achieving ideal mixing performance. Moreover, the complexity of the design process does not end with the theoretical design of the OFA jets. The trajectories, decay, and overall mixing of overfire jets within the furnace are also influenced by the flow of primary combustion products. Front-fired boilers in particular exhibit non-uniform velocity profiles at the OFA port elevation. A typical flow model velocity profile is shown in Figure 2. The furnace flow field is characterized by a high velocity region along the rear wall, and a low level recirculation area near the burner wall. This flow non-uniformity requires different OFA jet design criteria than classical jet theory based on uniform cross-flows. The experimental flow modeling approach used in this program is designed to properly simulate OFA jet trajectories and mixing in realistic furnace flow fields.

Modeling Criteria

A detailed discussion of the overfire air flow modeling criteria used in this program was described by Thompson et al. (1). A brief review of the important criteria is repeated here for completeness.

As with any scaled experimental modeling program, the use of a non-combustion model to investigate the performance of OFA systems is a viable tool only when the important parameters of the mixing process in the furnace are properly duplicated (2). In this case, there are two primary regions of interest, each requiring its own similarity criteria: 1) the burner region extending to the OFA port elevation; and 2) the region of injection and mixing, typically the region from the OFA ports to the furnace nose arch. The important features of each of these regions can be summarized as follows.

Burner Region - It is important to model the burner or flame zone, since this flow defines the inlet conditions for the overfire air mixing region. The effect of the momentum loss at the burner must be considered to achieve similarity with field boilers. Applying the Thring-Newby method (3) to the model burners allows for the conservation of burner jet momentum by geometrically distorting the burner diameter in the following manner:

$$\frac{d_m}{d_f} = \frac{1}{S} \left(\frac{\rho_a}{\rho_c}\right)^{1/2} ,$$

where S is the geometric scale factor, ρ is density, and d is the burner diameter. The density subscripts a and c refer to burner secondary air and furnace combustion product temperatures, respectively. The subscripts m and f denote model and field conditions.

Upper Furnace Region - The furnace section comprising the region between the OFA ports and the nose arch defines the mixing section in the furnace. Overfire air mixing is influenced by the characteristics of the cross-flowing furnace gases, as well as nozzle injection parameters. Jet trajectories are simulated by maintaining the momentum flux ratio ($\rho_o V_o^2 / \rho_f V_f^2$) where ρ is the gas density, V is velocity. The subscripts o and f denote OFA flow and total furnace gas flow, respectively. To a lesser extent, the effect of buoyancy can also influence the jet trajectory. The density-modified Froude number is used to account for this effect:

$$Fr = \left(\frac{\rho_o}{\rho_o - \rho_f}\right) \frac{V_o^2}{d_o g} ,$$

where d_o is the OFA port diameter and g is the gravitational force.

The furnace flow model is constructed to 1/12th scale and includes the furnace region from the hopper to the nose arch. The pressure loss of the convective pass is also incorporated to simulate its effect on the furnace flow patterns. The model represents a single-wall fired unit with a 4 x 4 burner matrix configuration. Overfire air ports are located one burner spacing above the top row of burners. Figure 3 is a schematic of the front-fired furnace flow model.

The penetration and mixing of the OFA jets with the bulk furnace flow in the model is determined by measuring the resulting local temperature when the two flows of different temperatures are mixed. In the test program, the burner flow is heated to approximately 180°F, while the overfire air flow is kept at ambient temperature. This ensures a ΔT of approximately 100°F for all test conditions. Local temperature variations within the model are used to evaluate mixing. The test model incorporates a fully automated thermocouple grid, which moves vertically to allow measurements at several elevations in the furnace. The equivalent field spacing between thermocouple grid nodes within the measurement plane is approximately 3 to 4 feet. Local temperatures are converted to OFA concentration values C_i by using the following equation.

$$C_i = \frac{m_o}{m_t} = \frac{T_f - T_i}{T_f - T_o} ,$$

where m_o/m_t represents the local mass flow ratio of OFA to total system mass flow. The temperature subscripts f and o denote main burner zone flow and OFA flow. T_i is the local measured mixed temperature.

A computerized data acquisition system allows for virtually instantaneous measurement and recording of all local furnace temperatures. The combination of careful flow rate calibrations and test model insulation translates into a flow balance accuracy of ±1.5% for burners and OFA ports, as well as temperature uniformity among burners of ±1°F. No measurable heat loss (<1°F) occurred in the model between the burner level and arch. In addition to detailed temperature measurements, velocity profiles are also measured to identify the prevailing flow profile. These profiles are taken at an elevation in the furnace just below the nose arch.

Data Analysis

No combustion tests were conducted to quantify the effect of jet mixing on NO_x reductions or combustion efficiency. However, the overfire air must mix with combustion products across the entire furnace cross-section to achieve good carbon burnout. Several performance criteria and data analysis techniques were used to compare the various OFA design configurations in the flow model. Model test data consisted primarily of temperature and velocity profiles. The velocity profile indicates the general flow distribution in the furnace. Temperature profiles were used to calculate the OFA concentration at each grid point. In addition, two and three-dimensional surface contour plots of OFA concentration, as well as flow visualization techniques (smoke, helium bubbles, video), were used to further enhance our ability to quickly and accurately compare test configurations. Videotapes of several operating conditions were recorded throughout the program to document key test results.

In order to evaluate and compare the mixing patterns among the various test configurations, an overfire air mixing index was established. Uniform mixing should produce a constant OFA concentration level, equal to the theoretical ratio of OFA to total mass flow ($C_i=m_o/m_t$). For conventional systems, in which 20% of total air flow is diverted to the OFA ports, an ideal mixing profile would show a consistent C_i of 0.2 everywhere at a given cross-sectional elevation. To compare data from various configurations, a range of concentration values around the theoretical mean was selected. For 20% overfire air addition, C_i values from 0.15 to 0.25 was chosen. More severe maldistribution of OFA concentration can result in poor overall combustion efficiency.

This analysis was used to arrive at a single index, N/N_T, to quantify and compare the degree of mixing achieved by different OFA systems. N/N_T is defined as the fraction of furnace cross-sectional area where the local OFA concentration, C_i, falls within a selected range. In our analysis of conventional OFA systems this range was 0.15 to 0.25. For advanced OFA systems with 45% OFA, a range of 0.40 to 0.50 was used. Unlike the local concentration C_i, values of N/N_T range from 0 to 1 with uniform mixing represented by a value of unity.

A further refinement to this mixing index can be made by accounting for the overall furnace mass flow distribution. Velocity profile measurements are required to determine the fraction of furnace mass flow within the selected concentration range. Both methods of analyses were used in this test program. However, the same conclusions were reached using either method.

OFA Configurations

The results of the test program can be divided into four major categories: 1) traditional designs with one OFA port above each burner column; 2) multiple wall designs with OFA ports located on up to four furnace walls; 3) alternate front wall designs with OFA ports serving specific regions of the furnace; and 4) advanced staging.

Initial testing focused on traditional OFA port designs typified by one port above each burner column and injection velocity ratios (V_0/V_F) ranging from 2 to 6. The results of this test series are summarized in Table 1. Mixing indices, N/N_T, are presented for two of the four upper furnace elevations at which mixing was evaluated. Velocity ratios of 4 and 6 produced the best overall mixing. Contour maps of OFA concentration profiles for each of the three velocity ratios are presented in Figure 4. These concentrations were measured at a furnace elevation, Z_2, slightly below the nose arch. Figure 4 demonstrates why it is very difficult to achieve a good mixing distribution throughout the furnace cross-section with conventional designs. High OFA injection velocity ($V_0/V_F=6$) results in deep penetration and impingement of the OFA jets on the far wall, and subsequent mixing with the furnace flow primarily near the rear and side walls of the furnace. The mixing near the side wall regions actually occurs due to the impingement of the jets on the far wall. This creates a back mixing effect which, in turn, fills the side wall channels. Similar overall mixing effectiveness can be achieved at $V_0/V_F=4$ without this rear wall back mixing. In the case of $V_0/V_F=4$, the OFA jets turn upward prior to impingement on the far wall, resulting in the mixing region being slightly closer to the burner wall. The lack of rear wall impingement results in lower coverage of the side wall regions. In both velocity cases, the burner wall area exhibits very low concentrations of overfire air due to the deep jet penetration.

The case of a low OFA jet velocity ($V_0/V_F=2$) suggests a different mixing profile due to the rapid jet deflection by the furnace bulk flow. Individual OFA jet profiles are still somewhat evident in the mixing contour map. This produces a mixing profile with high OFA concentrations in the center of the furnace and very low levels in the side wall channels.

These initial tests demonstrated that traditional OFA designs did not distribute air to all regions of the furnace. As a result of this performance, alternate OFA geometries were considered. Incorporating ports on alternate or multiple furnace walls was our first attempt at providing OFA ports for specific regions of the furnace. The results of this test series are summarized in Table 2. Test No. 6 with ports on all four walls showed a substantial improvement over traditional designs. A mixing index, N/N_T, of 0.89 corresponds to a near uniform OFA concentration profile across the furnace. This is achieved by the relatively rapid deflection and mixing of 12 low velocity ($V_O/V_F=2$) OFA jets. In comparison, the best N/N_T value obtained for conventional systems was 0.48. However, OFA ports on all four furnace wall are impractical due to cost and potential limitations resulting from interferences and structural design considerations. The importance of this test series was to provide a mixing standard for evaluating the performance of other design concepts. Therefore, no attempt was made to optimize the alternate furnace wall designs summarized in Table 2.

Limited Japanese field experience with various firing wall OFA designs served as the basis for selecting the next set of candidate OFA configurations (4). These configurations and selected operating conditions are summarized in Table 3. The main parameters evaluated in these tests were swirl, additional ports on the burner wall, and OFA flow and velocity bias. This test series demonstrated that good mixing can be achieved with single wall OFA designs. Swirl enhanced mixing near the burner wall. However, swirl did not produce added benefits when wing ports were added, as demonstrated by Test Nos. 9 and 11. An N/N_T mixing index of 1.0 was achieved in Test No. 12 by adding wing overfire air ports and establishing the proper flow and velocity bias. Figure 5 compares concentration profiles for Test Nos. 11 and 12 with a traditional design (Test No. 2) and OFA ports on four walls, (Test No. 6).

The contour plots in Figure 5c (Test No. 11) and 5d (Test No. 12) illustrate the sensitivity of mixing to OFA flow bias and injection velocities. As shown in Figure 5d biasing both velocity and flow bias between the center and wing ports results in improved penetration and mixing along the furnace side walls. The two cases represent operating conditions with a flow bias of 60% to 40% between the center ports above each burner and wing OFA ports. However, the velocity ratio of the wing jets in Figure 5d was increased from 3.0 to 4.5. The contour plots reveal well mixed profiles in both cases with approximately 80% and 100% coverage for each case. The higher wing jet velocity in Figure 5d provides the added penetration required to achieve the desired mixing levels near the side walls and far corners.

The results presented in Figures 4 and 5 describe mixing just below the furnace arch. Improved mixing at lower furnace elevations may be required in cases where upper furnace residence time for carbon burnout is limited. Therefore, the benefits of adding auxiliary OFA ports between burner columns were evaluated. In Figure 6, profiles at two furnace elevations are presented for Test Nos. 12 and 14. Auxiliary ports were added in Test No. 14 specifically to enhance mixing along the front firing wall. Earlier tests had shown that low OFA injection velocities were effective in achieving this effect. In Test No. 14, the flow bias and injection velocities were refined to achieve good OFA mixing at lower furnace elevations. The results are reflected in an OFA mixing index, N/N_T, of 0.76 obtained approximately midway between the OFA ports and furnace arch. A corresponding index of 0.55 was achieved at the same furnace elevation in Test No. 12 without auxiliary ports between burner columns.

Advanced OFA systems using 40% of the total combustion air as overfire air were also tested. These results are summarized in Table 4. Only two configurations were evaluated: a traditional front wall design (Test No. 15) and a system with OFA ports on the side walls (Test No. 16). For advanced staging systems, the same design principles and criteria apply as for conventional staging. However, because of the large quantities of overfire air, rapid mixing for carbon burnout is more critical. Since the emphasis of the test program was on conventional OFA systems, additional testing is required to better understand and evaluate advanced OFA design concepts.

FEASIBILITY STUDIES

The objective of the flow model tests was to improve the mixing of overfire air with the combustion products leaving the burner zone. In an actual boiler retrofit situation, there are many practical mechanical, structural and design limitations that must also be addressed. The structural integrity of the burner wall, interferences with other existing equipment, and economics may be the overriding factors that determine the number and arrangement of OFA penetrations. Although it is theoretically possible to modify boiler structural members to accommodate most proposed OFA designs, the best retrofit will be a design that minimizes NO_x and unburned carbon for reasonable costs.

Technical and economic analyses of retrofitting several OFA systems were performed on a front-fired boiler design case in order to assess these practical design constraints. The case study unit, shown in Figure 7, is a representative 400 MWe natural circulation reheat boiler. It is equipped with 24 burners mounted on four rows. One obvious design limit is the relatively short distance between the top row of burners and the bottom of the superheater platens. Overfire air mixing and carbon burnout must be completed within this distance. The overfire air ports must also be located between existing structural members such as buckstays. This wall section could accommodate several OFA system layouts, with varying port numbers, port geometries and design flow rates. Aerodynamic mixing, combustion, heat transfer, and structural analyses must now be employed to assess the technical impact of installing these systems. The final decision would be based on the predicted technical feasibility of each design, as well as the predicted retrofit costs.

The required technical considerations include: aerodynamic mixing; necessary flow controls; NO_x predictions based on degree of staging and furnace heat release parameters; residence times required to complete combustion; impact on furnace heat transfer and furnace exit temperatures; and feasibility of installing the OFA penetrations without major structural modifications to the boiler. Various flow model test configurations were evaluated. Other EPRI NO_x control programs provided the basis for predicting NO_x reductions (5). These pilot scale studies also identified the potential for decreased combustion efficiency under staged combustion conditions.

Retrofit costs were evaluated using the EPRI Economic Premises for Electric Generating Plants, issued in December, 1982 (6). Proposed designs of the required ductwork, flow controls, and boiler structural modifications were generated for each OFA system. Materials and construction costs were estimated using Riley's design data base. All costs were calculated using 1983 construction costs, and escalated to 1986 dollars using published escalation rates (7). The cost estimates use a 20% Class II project contingency and a 20% process contingency.

Table 5 summarizes costs for five overfire air systems. These include four design approaches for conventional systems, plus one advanced OFA case in which 40% of the total combustion is directed to the overfire air system. The estimates show that costs fall into two general categories: 1) Systems that require windbox extensions, but no extensive structural changes or OFA ports on multiple walls, require 1 - 2 \$/KW; 2) systems that require a separate OFA windbox, such as advanced staging or designs that require installing ports on walls in addition to the burner wall, require approximately 6 - 7 \$/KW. Costs influenced by structural considerations in particular will be site-specific. Therefore, several overfire air options for each candidate retrofit boiler should be evaluated before the final design is specified.

Cases 1 through 4 illustrate that designs with improved OFA mixing characteristics are not necessarily the most expensive design option. Case 1, a conventional design with one OFA port above each burner column, was the least expensive retrofit considered. The OFA designs in Cases 2, 3, and 4 all showed substantial improvements over conventional designs in our flow model studies. The predicted retrofit costs for these systems, however, are significantly different. Installing overfire air ports on all four boiler walls (Case 2) is the most expensive option considered. The costs illustrate that, while this system is effective in promoting overfire air mixing, the retrofit costs make it impractical. The mixing indices obtained from the flow model results show that adding wing ports and biasing flow between the center and wing ports improves OFA mixing substantially. Our economic analyses indicate that these improvements (Case 3) will cost approximately 10% more than conventional systems (Case 1). Adding the auxiliary ports between the burner columns (Case 4) results in approximately a 30% increase in costs. However, in order to install this sytem without making structural changes to the boiler, an engineering evaluation showed that round OFA ports could not be used. The port shape for Case 4 only was changed to elliptical with a 2.5 to 1 aspect ratio. Brief flow model tests indicated that ports with aspect ratios up to 3 to 1 behaved similarly to round ports

Case 5 is an advanced staging system. The cost of this system is significantly higher, since diverting 40% of the combustion air to the staging system requires a separate OFA windbox with additional flow controls. Case 5 also requires a slight modification to the OFA port design. Because higher flow rates require larger port diameters, it was not possible to install the wing OFA ports with the center ports directly above each burner column unless major structural reinforcements were added to the burner wall. Instead, the OFA ports were spaced equally across the burner wall. Provisions to bias OFA flow between center and wing ports are still included. A comparison of Cases 3 and 5 illustrates the estimated cost difference between conventional and advanced OFA systems.

RETROFIT DESIGN GUIDELINES

These guidelines address the design of conventional overfire air systems for front-fired boilers. Conventional systems divert 10 to 30% of the total combustion air to overfire air ports. Since no combustion tests were conducted to quantify the effect of jet mixing on NO_x emissions or carbon burnout, our recommendations are based on the criterion that the OFA must mix with the combustion products across the entire furnace cross-section to achieve good carbon burnout. Both flow model and feasibility study results have shown that a number of parameters must be considered in designing effective overfire air systems. The location and number of OFA ports, the OFA injection velocity, and the flow bias between ports can have significant effects on OFA mixing and retrofit economics.

Flow model studies have also shown that existing jet trajectory correlations alone are not sufficient to design good OFA systems. These empirical correlations do not address several important furnace flow conditions:

- Single wall fired boilers have unique, non-uniform flow patterns with large recirculation zones. Traditional correlations for jet mixing assume uniform crossflows. Mixing in furnaces is also driven by secondary flows generated by recirculation.

- Traditional jet trajectory correlations only predict mixing in one plane. OFA mixing in a boiler is a three-dimensional problem. The lateral coverage of OFA jets is as important as jet penetration across the furnace depth.

Traditional OFA Designs Traditional OFA system designs are defined as systems with one OFA port above each burner and equal air flow to all ports. The best OFA mixing in the flow model occurred at velocity ratios V_O/V_F between 4 and 6. This design is referred to as the base case OFA design in these guidelines. In front-fired units, most of the combustion product mass flow is near the rear wall. V_O/V_F between 4 and 6 achieved good OFA mixing along the rear wall and in the corners near the rear wall. Mixing was not satisfactory, however, along the burner wall and in the corners near the burner wall. Combustion tests are required to quantify the effects of poor OFA mixing in these regions on carbon burnout.

At an OFA injection to furnace velocity ratio $V_O/V_F=2$, OFA did not penetrate to the rear wall to mix with main combustion product mass flows. For example, the OFA mixing at $V_O/V_F=6$ was twice as good as with $V_O/V_F=2$. OFA injection velocity ratios <2, therefore, appear too low for traditional OFA designs. At $V_O/V_F > 6$, the OFA jets impinged on the rear furnace wall and rolled downward along the wall into the burner region. This downward mixing could have an adverse effect on the degree of NO_x control achieved. OFA injection velocities in this range, therefore, are not recommended.

The preceding test results are all based on circular OFA ports. At V_O/V_F between 4 and 6, the OFA port diameter is reasonable, i.e., less than the burner diameter. Preliminary model test results suggest that rectangular OFA ports with a height to width aspect ratio up to 3:1 can also be used at V_O/V_F between 4 and 6. More model testing is required to verify this. Rectangular or elliptical ports may have an economic advantage over round ports in some retrofit cases, since fewer tube bends would be required to install them. These traditional OFA designs with one OFA port above each burner column were the lowest cost option evaluated. The total capital cost requirement for retrofitting these systems to existing boilers is 1.3 $/kW. This cost estimate is based on the following assumptions: 1) the existing windbox would be extended to accommodate the OFA system; 2) a booster fan is not needed; and (3) the OFA control system would include on/off flow controls and adequate dampers to control the amount of air flow, but would not be designed to modulate the OFA flow over a wide range.

OFA on Alternate Boiler Walls OFA mixing can be improved by placing OFA ports on walls other than the burner wall in front-fired boilers. Given the freedom to utilize OFA ports on all four furnace walls, flow model tests showed that this configuration significantly improved mixing across the furnace cross-section. Recommended design parameters for this system are: 1) maintain the same OFA port spacing along the side and rear walls as on the front wall (i.e., OFA spacing equals horizontal burner spacing); and 2) reduce V_O/V_F to 2. OFA injection velocities can be reduced since the jets don't have to penetrate as deeply into furnaces.

The total capital required for a conventional OFA system installed on all four boiler walls is 7.2 $/kW vs. 1.3 $/kW for the traditional base case design. There are practical as well as economic constraints in installing an OFA system on all four burner walls. Potential problems with installing an OFA windbox on the rear wall, in particular, include interferences with downcomers, economizer hoppers, and boiler convective sections that may extend near or below the top burner elevation.

Alternate Front Wall OFA Designs Recommended injection velocity ratios of 4 to 6 are effective in creating a well-mixed zone near the furnace rear wall. However, the front wall above the burners and near the corners remains starved of OFA. Improvements of OFA mixing near the front walls can be achieved by adding wing OFA ports and biasing both OFA mass flow and velocity across the front firing wall. Flow model tests showed that OFA jet swirl was not required under these conditions.

Wing OFA ports are used to promote mixing in the corners and furnace sidewalls. Recommended design conditions for this system are:

- Center ports: $V_O/V_F = 3$ to 4
  55-65% of the total OFA flow

- Wing ports: $V_O/V_F = 4$ to 6
  35-45% of the total OFA flow

Further improvements to OFA systems on the firing wall may be made by adding auxiliary ports without swirl between burner columns to improve lateral mixing. The auxiliary OFA ports can be used to promote mixing along the front wall, while other ports are designed to penetrate toward the furnace rear wall. Since this configuration locates OFA ports between burner columns, a structural analysis should be performed. Recommended design conditions for this system are:

- Center ports: $V_O/V_F = 4$
  55-65% of the total OFA flow

- Wing ports: $V_O/V_F = 5.5$
  25-35% of the total OFA flow

- Auxiliary Ports: $V_O/V_F = 1$
  10-20% of the total OFA flow

The estimated capital cost for these alternate front wall designs ranges from 1.4 to 1.7 $/kW.

SUMMARY

Flow modeling techniques have been used to evaluate new OFA designs and to develop preliminary design guidelines for front-fired boilers. Further work is required to develop similar guidelines for other boiler configurations. Since the improved design concepts discussed here have not been implemented commercially, combustion tests are required to evaluate impacts on boiler performance parameters such as carbon burnout.

REFERENCES

1. Thompson, R., Eskinazi, D., Afonso, R., Gilbert, G., Yang,R. and McHale, C. Laboratory Flow Model Studies to Improve Overfire Air Mixing. In: Proceedings of the 1985 Symposium on Stationary Combustion NO_x Control, Vol. I, 1986.
2. Anson, D. Modeling Experience with Large Boilers. Journal of the Institute of Fuel, January 1967.
3. Thring, M.W. and Newby, M.P. Combustion Length of Enclosed Turbulent Jet Flames. In: Fourth (International) Symposium on Combustion, Baltimore, 1953.
4. Tsuji, S., Aoki, K., and Sakai, T. Improvement of the Two Stage Combustion Method for Reduction of Nitric Oxide. IHI Engineering Review, Vol. 9 No. 2.
5. Lisauskas, R., Snodgrass, R., Johnson, S., and Eskinazi, D. Investigation of Retrofit Low-NO_x Combustion Systems. In: Proceedings of the 1985 Symposium on Stationary Combustion NO_x Control, Vol. I, 1986.
6. EPRI Economic Premises for Electric Power Generating Plants, December 1982.
7. Engineering News Record. ENR Market Trends, Cost Indices. June 30, 1983 and January 8, 1987.

Reproduced from
best available copy.

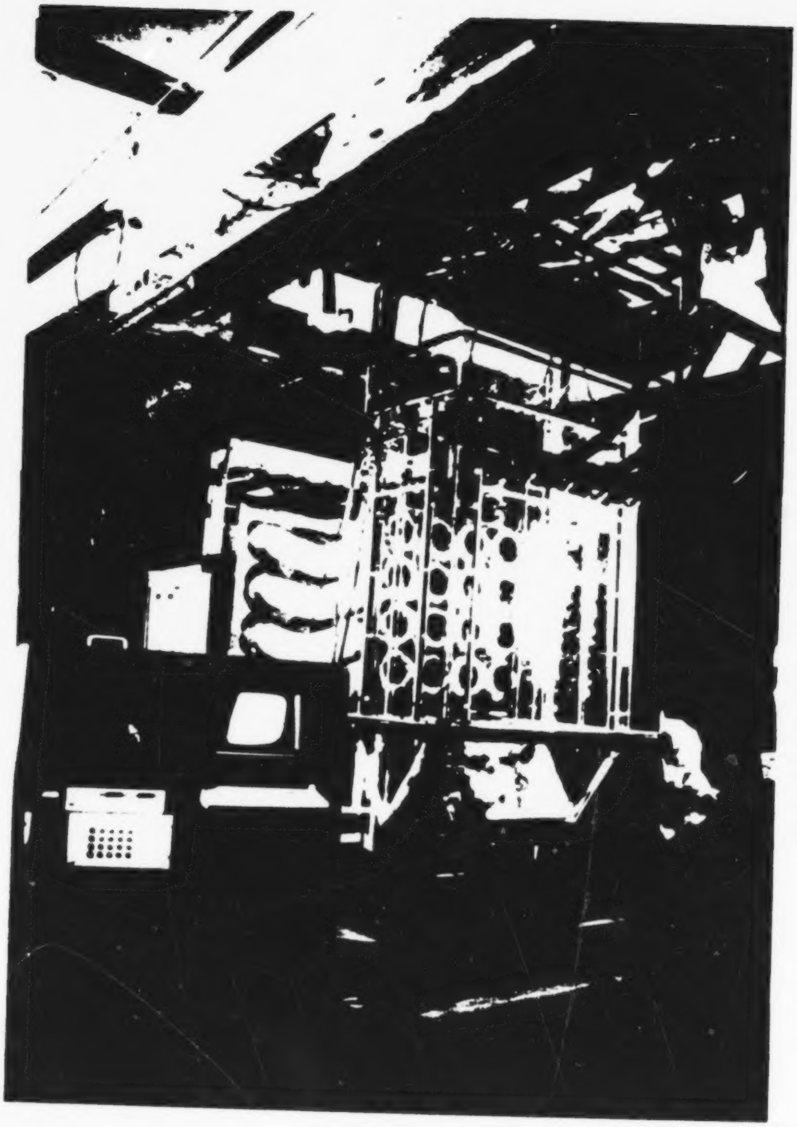


Figure 1. Laboratory Flow Model with Burner Detail

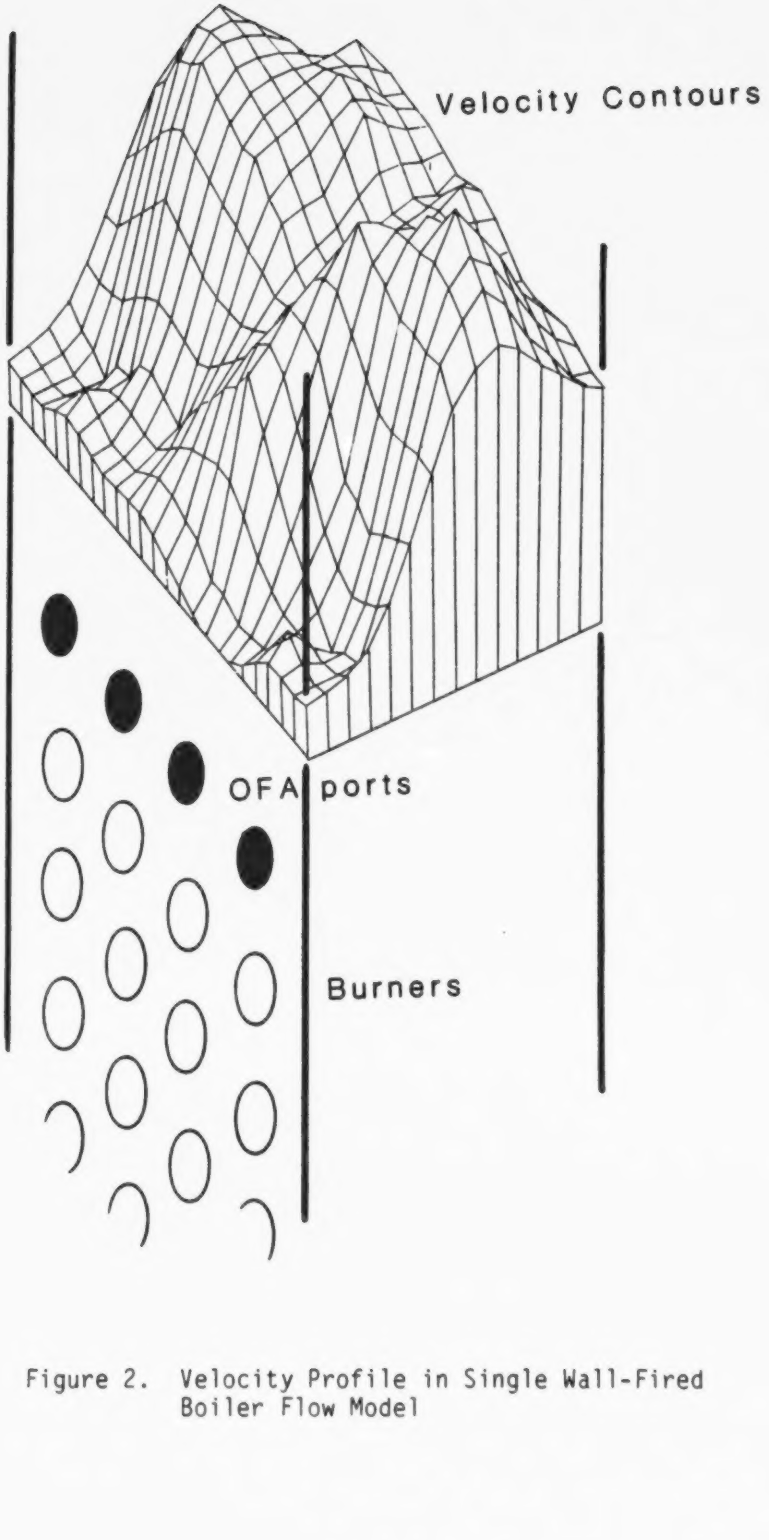

Velocity Contours
OFA ports
Burners

Figure 2. Velocity Profile in Single Wall-Fired Boiler Flow Model

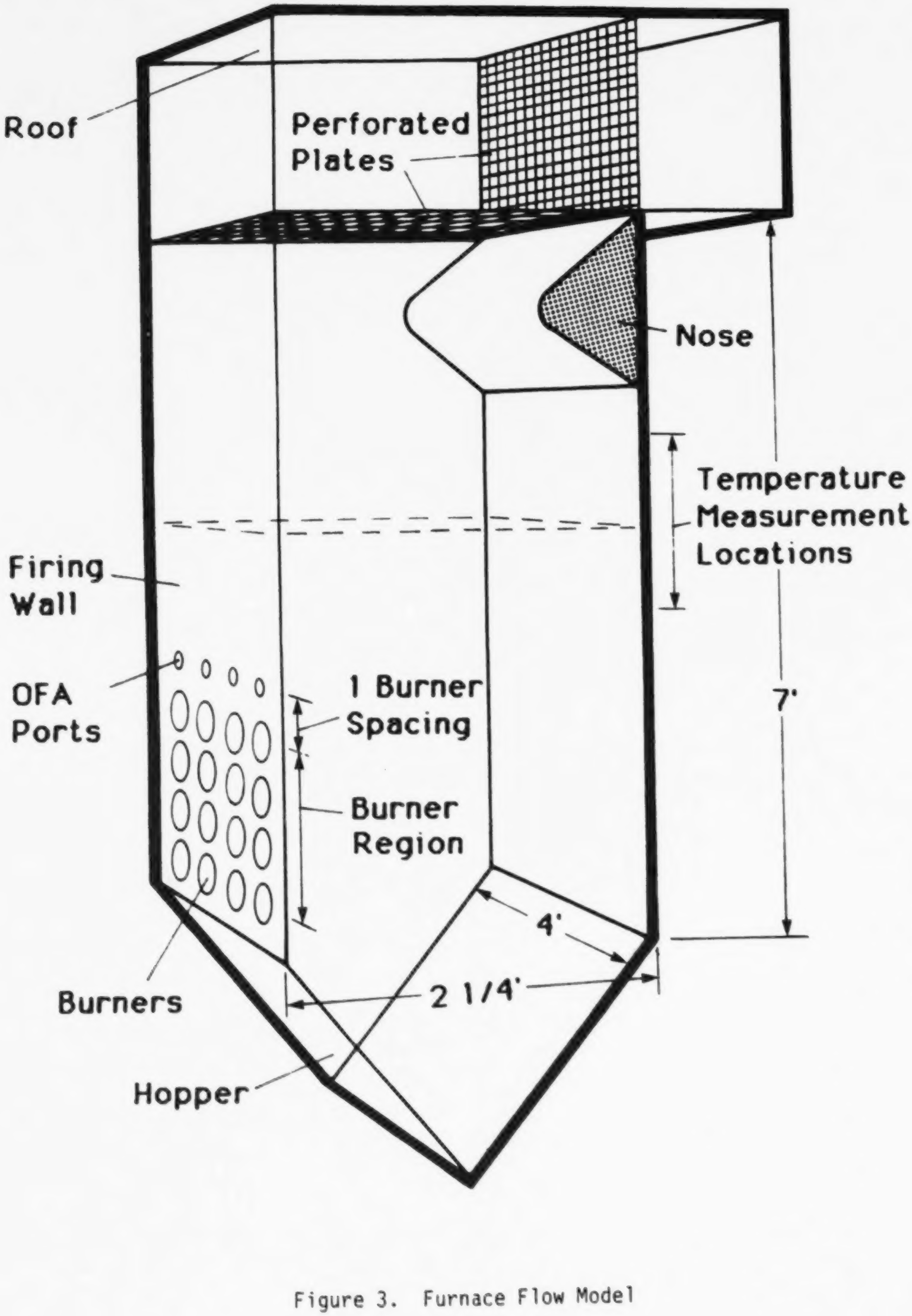

Roof
Perforated Plates
Nose
Temperature Measurement Locations
Firing Wall
OFA Ports
1 Burner Spacing
Burner Region
7'
4'
2 1/4'
Burners
Hopper

Figure 3. Furnace Flow Model

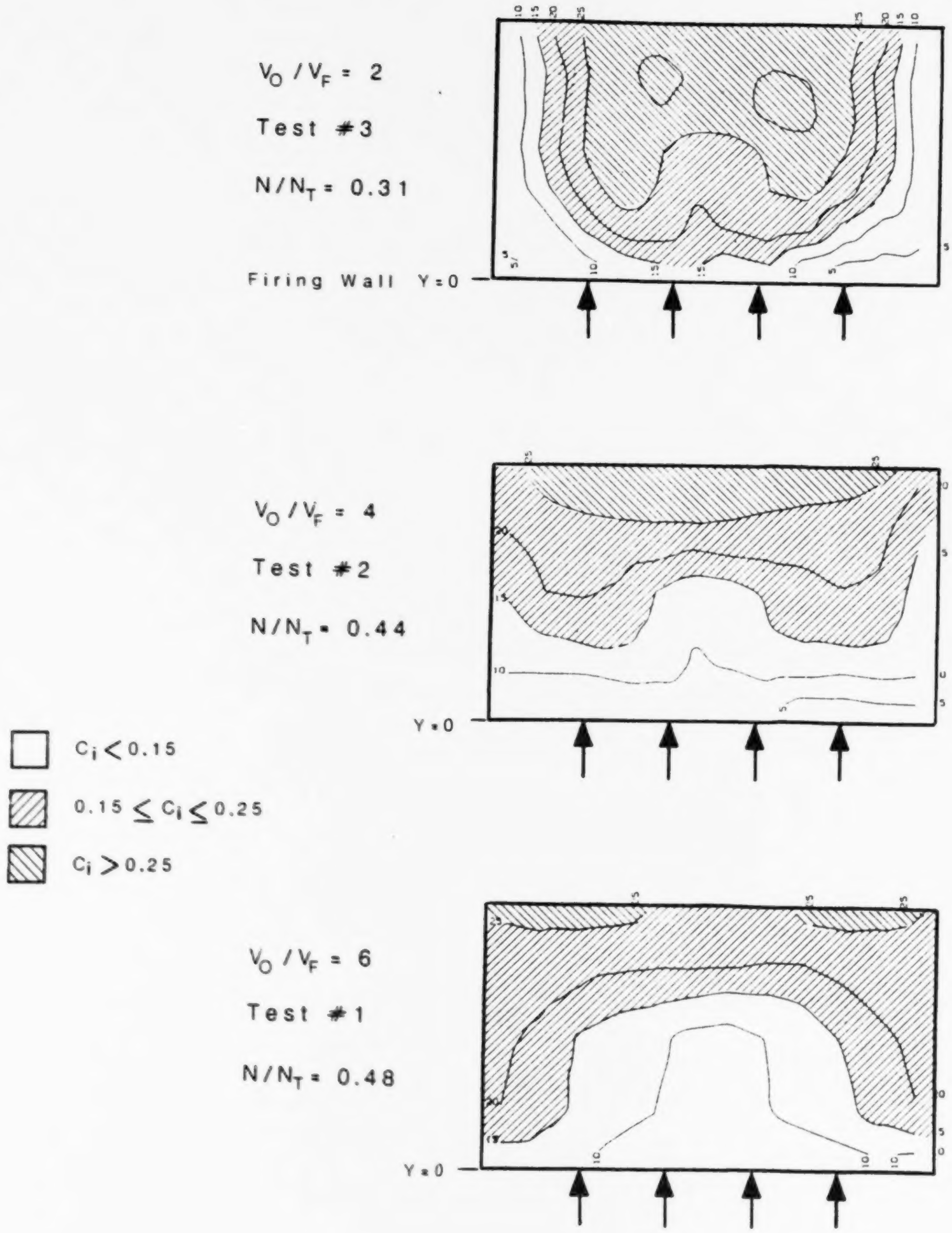


Figure 4. Influence of Overfire Air Injection Velocity Ratio on Mixing in the Flow Model

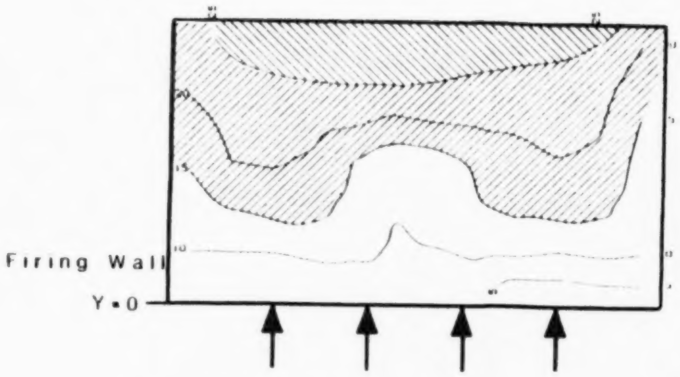


Figure 5a. One Port Above Each Burner Column (Test #2, $N/N_T = 0.44$)

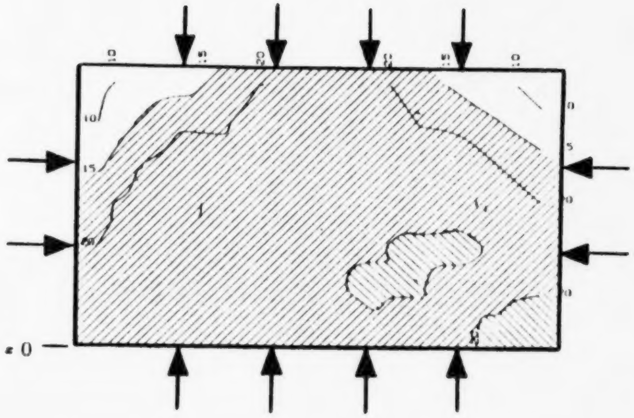


Figure 5b. Ports on Four Walls (Test #6, $N/N_T = 0.89$)

☐ $C_i < 0.15$

▨ $0.15 \leq C_i \leq 0.25$

▨ $C_i > 0.25$

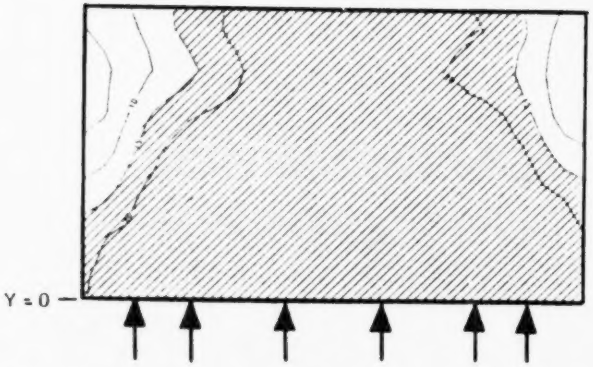


Figure 5c. Central Plus Wing Ports With Flow Bias (Test #11, $N/N_T = 0.83$)

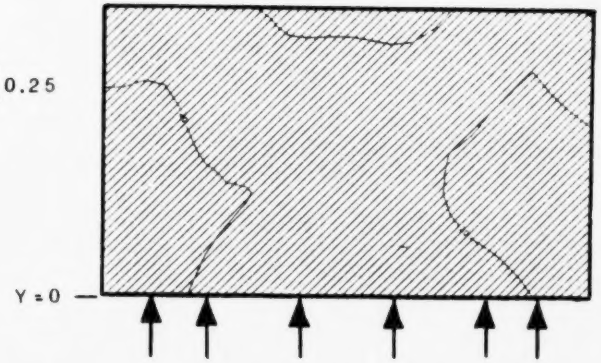


Figure 5d. Central Plus Wing Ports With Flow and Velocity Bias (Test #12, $N/N_T = 1.0$)

Figure 5. Comparison of OFA Mixing Achieved with Novel OFA Port Arrangements

Center and Wing OFA Ports with Biased Flow (Test #12)

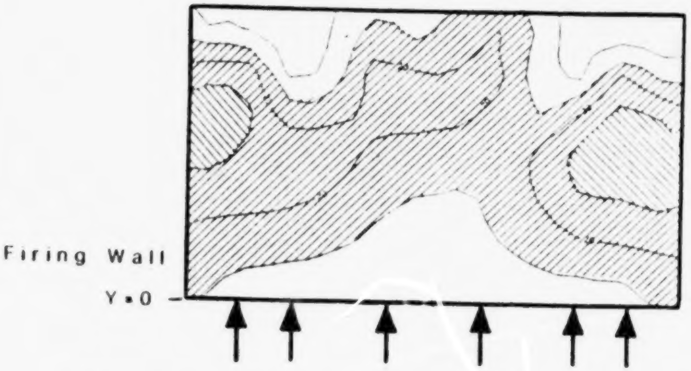


Figure 6a. Mixing Measured Between OFA Ports and Furnace Arch ($N/N_T = 0.55$)

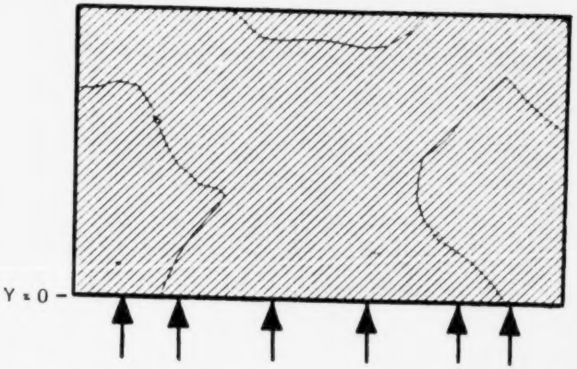


Figure 6b. Mixing Measured at Furnace Arch ($N/N_T = 1.0$)

□ $C_i < 0.15$ ▨ $0.15 \leq C_i \leq 0.25$ ▧ $C_i > 0.25$

Center, Wing, and Auxilliary Ports with Biased Flow (Test #14)

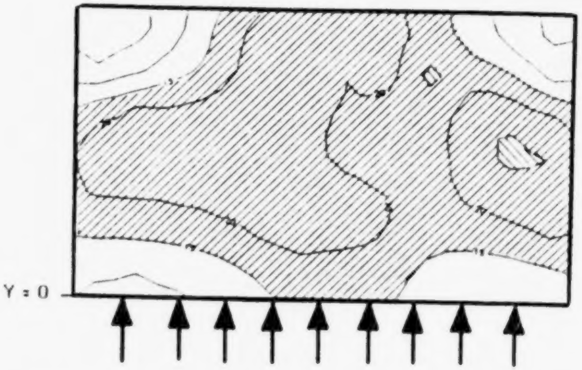


Figure 6c. Mixing Measured Between OFA Ports and Furnace Arch ($N/N_T = 0.76$)

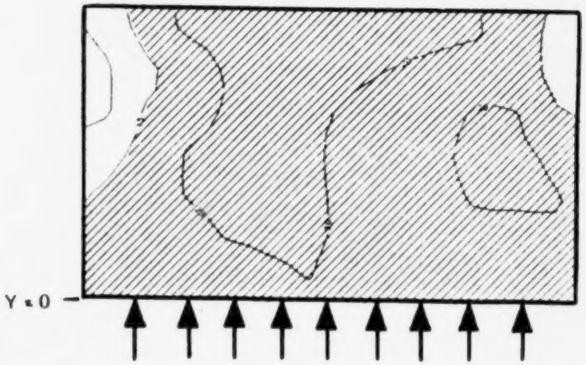


Figure 6d. Mixing Measured at Furnace Arch ($N/N_T = 0.92$)

Figure 6. Influence of Auxilliary OFA Jets on Mixing in the Flow Model

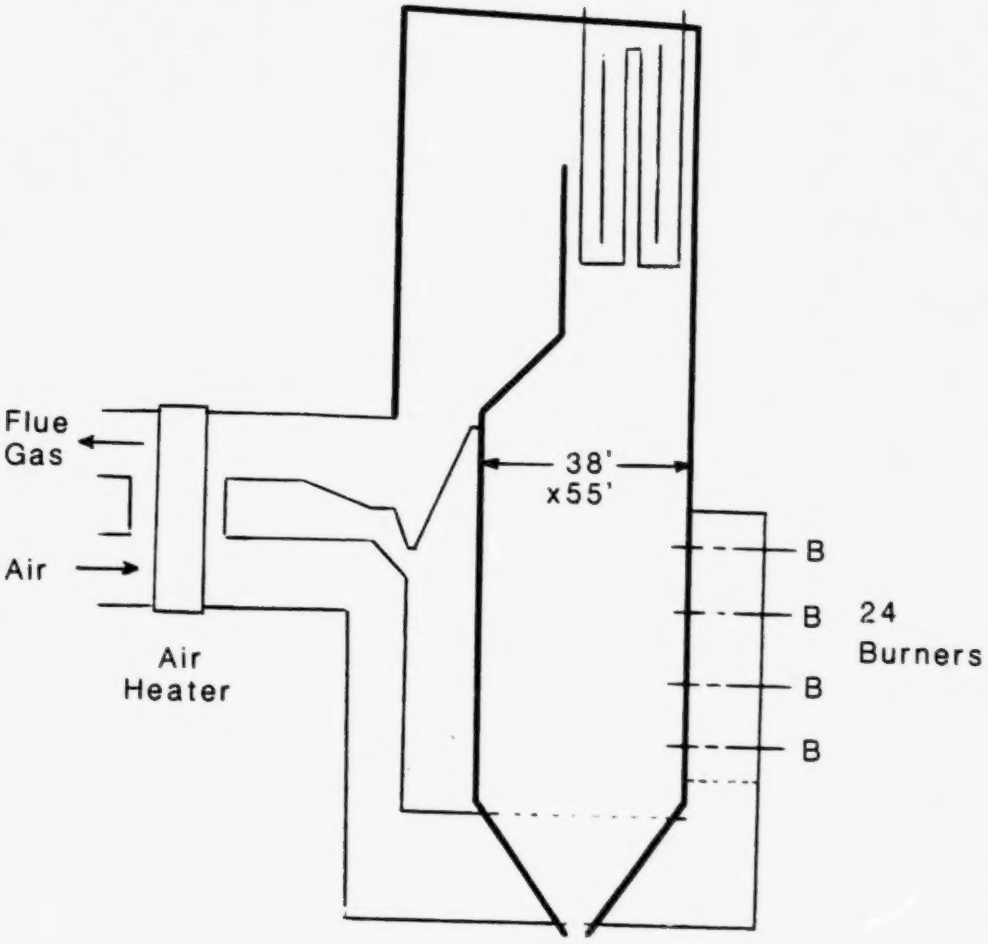
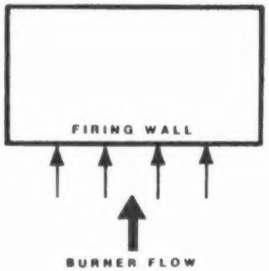

Flue Gas
Air
Air Heater
38' x55'
B
B
B
B
24 Burners

Figure 7. 400 MW Feasibility Study Boiler

Table 1

Traditional OFA System Tests

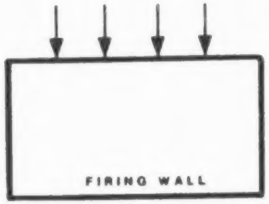
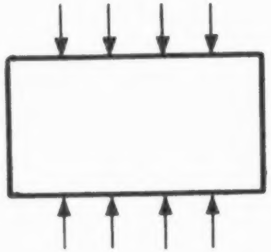
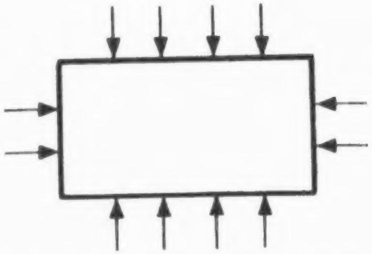
(one OFA port above each burner column, 20% OFA)

Test Case	**System Sketch (Plan View)**	**Flowrate Per Port (%)**	V_0/V_F	**Mixing Index N/NT** Z_1*	Z_2*
1		25	6	0.37	0.48
2		25	4	0.30	0.44
3		25	2	0.20	0.31

*Z_1 Midway between OFA ports and furnace arch
Z_2 Furnace arch elevation

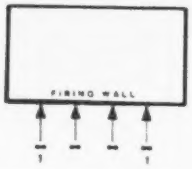
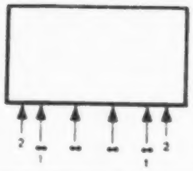
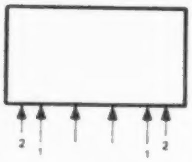
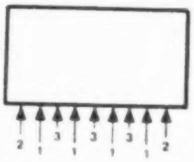
Table 2

Alternate Boiler Wall OFA System Tests (20% OFA)

Test Case	System Sketch (Plan View)	Flowrate Per Port (%)	V_0/V_F	Mixing Index N/NT	
				Z_1*	Z_2*
4		25	6	0.25	0.30
5		12.5	2	0.35	0.50
6		0.83	2	0.74	0.89

*Z_1 Midway between OFA ports and furnace arch
Z_2 Furnace arch elevation

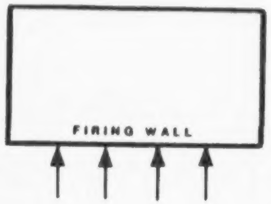
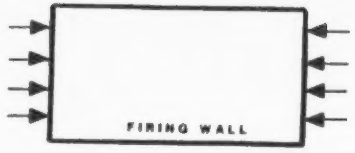
Table 3
Alternate Front Wall OFA System Tests (20% OFA)

Test Case	System Sketch (Plan View)	Port #	Flowrate Per Port (%)	V_O/V_F	Mixing Index N/NT Z_1*	Z_2*
7		1	25	4	0.43	0.48
8		1	16.7	1.5	0.16	0.32
		2	16.7	3		
9		1	15	3	0.50	0.70
		2	20	3		
10		1	16.7	2	0.11	0.39
		2	16.7	2		
11		1	15	3	0.63	0.83
		2	20	3		
12		1	15	3	0.55	1.0
		2	20	4.5		
13		1	12	4	0.60	0.99
		2	20	4.5		
		3	4	2		
14		1	14.5	4	0.76	0.92
		2	15	5.5		
		3	4	1		

*Z_1: Midway between OFA ports and furnace arch
Z_2: Furnace arch elevation

Table 4

Advanced OFA System Tests (40% OFA)

Test Case	System Sketch (Plan View)	Flowrate Per Port (%)	V_o/V_F	Mixing Index N/NT Z_1*	 Z_2*
15		25	4	0.29	0.33
16		12.5	4	0.39	0.51

*Z_1 Midway between OFA ports and furnace arch
Z_2 Furnace arch elevation

Table 5

Feasibility Study Results

Case No.	OFA System Description	Mixing Index N/NT	Total Capital Requirements ($/kW)
1	Conventional OFA (20% staged air); one OFA port above each burner column; $V_O/V_F = 4$	0.44	1.3
2	Conventional OFA; ports on all four furnace walls; $V_O/V_F = 2$	0.89	7.2
3	Conventional OFA; one center port above each burner column plus "wing" ports; bias OFA flow between ports	1.0	1.4
4	Conventional OFA; center, wing, and auxiliary ports; bias OFA flow among ports	0.92	1.7
5	Advanced OFA (40% staged air); one center port above each burner column plus wing ports; bias OFA flow between ports	N/A	5.7

Furnace Design and Application on Low NOx Pulverized Coal Combustion

by Takashi KIGA, Shigehiro MIYAMAE
Keiji MAKINO, Hiroshige IKEBE

Ishikawajima-Harima Heavy Industries Co., Ltd.
Boilers R & D Dept., Boiler Plant Division,
3-13, 5-chome, Toyo, Koto-ku, Tokyo, 135, Japan

ABSTRACT

Coal properties such as fuel ratio and fuel nitrogen are generally well-known to give an effect on NOx emission. We have already developed low NOx pulverized coal burner which gives 150 ppm of NOx or less for Japanese domestic coal with conventional staged firing, however, most of various kinds of imported coals ensured significant higher NOx emission with conventional type furnace. Therefore, we attempted to develop low NOx type furnace applied the method named INPACT, according to the results of the fundamental researches.

With application of this method to a 600 MW utility boiler, in conclusion, we obtained low NOx emission of less than 150 ppm of the guarantee value for coals ranked from 1.5 to 2.2 as fuel ratio and remarkable NOx reduction of less than 100 ppm was also obtained.

This paper introduces the fundamental furnace design concept and its application results.

INTRODUCTION

Recently, in utility power boilers and industrial boilers, it has become common to use various kinds of coal from foreign countries with the purpose of expanding fuel supply sources and political reasons in Japan. For foreign coals, the coal properties have wide variations by the origin and it is well known that this largely affects combustion performance and NOx emission characteristics. NOx formation during coal combustion is mainly governed by fuel NOx originated by fuel nitrogen(1), which can be divided in two phases(2); one is gas phase volatile nitrogen evolved in the process of coal pyrolysis and the other char nitrogen in residual char. The difficulties of NOx reduction on coal firing are due to the complexity of NOx formation by volatile and char nitrogen, which depend not only on coal properties but also on temperature and heating rate of coal particles in the process of coal pyrolysis(1)(2), and the amount of coal bounded nitrogen. Generally speaking, it is recognized that higher volatile coals such as sub-bituminous coal have a tendency to easily reduce NOx emission which mainly originated by volatile nitrogen, from field result which realized 150 ppm or less NOx emission(3) by conventional staged firing with low NOx pulverized coal burner for Japanese domestic coals. Therefore, we have concentrated on how to control NOx emission for various kinds of coal, having relatively lower volatile, ranked from 1.5 to 2.5 as fuel ratio.

To reduce NOx emission from pulverized coal firing boilers, we have conducted fundamental researches by using electrically heated reactor, small and large scale test furnaces to clarify NO formation and destruction characteristics under fuel rich condition. According to the above fundamental researches, the INPACT method, which is developed by IHI and NO reduction by expanding residence time in fuel rich process, was confirmed to be effective to control NOx emission.

FUNDAMENTAL RESEARCH

NOx formation and destruction characteristics was experimentally investigated by using electrically heated (3 division control) flow reactor. Fig. 1 shows a schematic flow diagram of flow reactor. Dried pulverized coal was fed to the top of alumina reactor (ø47 mm in diameter, 1.2m in length) through magnetic type micro feeder with N_2. Oxygen was fed from the top of the reactor and through alumina probe inserted from bottom of the reactor, respectively. Gas analyzing was achieved from sample gas through hot water cooled probe inserted from bottom of the reactor. Unreacted char particles were also accumulated to the char pot installed at the outlet of reactor and analyzed. The method of analyzer is tabulated in Table 1. Experiments were conducted under 1 g/min of pulverized coal flow with total reaction gas (the sum of N_2 and O_2) flow of 10 ℓ N/min. The effects of reactor wall temperature and stoichiometry on the formation of nitrogeneous species were investigated by the deviation of oxygen feed rate under constant reaction gas flow. As preliminary evaluation, coal nitrogen released was correlated with reactor wall temperature using coal particles of 70% pass through 200 mesh (74μm) sieve for A coal, of which property is shown in Table 2. The results are shown in Fig. 2, and empirical correlation between coal nitrogen released η_N and wall temperature T (K) is expressed as a function of coal conversion η as follows;

$$\eta_N = \eta^{n(T)}, \quad n(T) = 2.0 \times 10^{-2} \exp(5770/T)$$

The formation of nitrogeneous species (NO, NH_3, HCN) was expressed in Fig. 3, along with air stoichiometry at 1400°C of wall temperature for 2.0 sec of residence time. As expected, NO was reduced and HCN was formed with lowering air stoichiometry. NH_3 has a tendency to be gradually formed and then to be reduced with lowering air stoichiometry, although the values are relatively dispersed.

Above data are the case for long time reaction under fuel rich condition. Therefore, we also investigated the activity of nitrogeneous species for volatile-N on reaction time, using gaseous fuels. Since HCN was believed as major species as volatile-N, volatile-N was simulated by pyrolysis of CH_4 with NH_3 under lack of O_2. Simulated volatile-N such as HCN and NH_3 was also oxidized by O_2 injection with N_2. The profile of volatile-N was shown in Fig. 4 along with reaction time. Total fixed nitrogen (TFN), defined as the sum of HCN, NH_3 and NO, could be reduced with reaction time under fuel rich condition and we noted that the destruction of HCN governed TFN emission. Furthermore, we also studied the effect of HCN content in nitrogeneous species on volatile-NO_x formation after air injection as staged firing. The results were shown in Fig. 5. It was made clear that HCN content in TFN had a big effect on final NOx formation under staged combustion.

According to the above results, we investigated the effect of staging port location on NOx formation at small size (1.2 MWt) tunnel test furnace. The coal properties used in this test are also shown in Table 1 (B and C coal). With increasing the distance of staging air port from burner face, NOx emission of both coals could be reduced drastically as shown in Fig. 6 and it was made clear that this result supported that of bench scale experiment(4),(5).

Finally, we also conducted other firing test at large scale test furnace (12 MWt) to compare NOx reduction characteristics due to coal property. As mentioned before, volatile matter content of coal was expected to give some differences on NOx reduction due to the differences of volatile-N released during coal combustion, and therefore we tested three different coals (D, E, F coal in Table 1) for the purpose of comparison. As was expected, the effect of coal volatile on NOx reduction by air staging was significantly large as shown in Fig. 7.

As a result, on the design of low NOx coal firing furnace, it can be recognized that the residence time of reducing region is determined in consideration of the variations of volatile matter content for various kinds of coal used.

FURNACE DESIGN AND APPLICATION OF LOW NOx PULVERIZED COAL COMBUSTION

To realize low NOx combustion on coal firing boilers, some of fundamental combustion technologies will be required as follows,

(1) Adoption of low NOx pulveriged coal burners and optimization of burner arrangement.

(2) Optimization of fuel/air distribution to individual burners to avoid unbalance of firing condition across furnace width.

(3) To avoid ash deposit or slagging troubles in furnace.

(4) Control of fuel and air supply to the furnace to meet the requirement of rapid load changing.

For the item (1), we have already developed and applied the dual flow (DF) type low NOx burner, and consequently obtained less than 150 ppm of NOx emission for Japanese domestic coals. Burner arrangement will be decided not only by cross-sectional heat libration rate to avoid slag deposit concerning with item (3) but also by the possibilty of flame interaction. Furthermore, burner zone heat liberation rate is directly concerning with flame temperature, which also give some effect on thermal NOx formation and on the oxidation rate of char particles.

On the second item, fuel/air distribution to individual burners will depend on the arrangement of coal pipe and individual air duct with damper instead of common windbox and also on the performance of coal distributors equipped with coal pipes or pulverizers. We will note that O_2 balancing across furnace width always give better effects on both reductions of NOx emission and unburned combustible in fly ash.

In addition to the above fundamental design concept, we have also progressed the development of low NOx furnace adopted INPACT method in accordance with the fundamental researches described previously. INPACT method named by IN-furnace Pollution Abatement Combustion Technology or IHI NOx Preventing Advanced Combustion Technology is schematically shown in Fig. 8 with other low NOx firing such as conventional air staging and reburning technology. Prior to the development of

INPACT method, we have also studied the reburning technology(6)(7), and made clear that this was not effective to realize very low NOx emission on coal combustion due to the oxidation of fuel-N in reburning coal and the difficulties on such as fuel spreading and control of oxidation with volatile released by reburning. INPACT method is so-called multiple air staging technology with over-fire air port (OAP), inter-stage air port (IAP) and side air port (SAP) as also shown in Fig. 8.

Main staging air through OAP controls NOx emission, and additional air injection through IAP contributes to protect waterwall corrosion and slag deposit at reducing region. IAP air also give a function to automatically control O_2 balance across furnace width in such case as soot blowing because O_2 unbalance generally causes NOx increment at low NOx condition. SAP is installed between OAP or burner and furnace side wall. Air feed through SAP contributes to promote char oxidation along with furnace side wall in complete combustion region, according to the fact that atmospheric temperature near the furnace side wall is generally lower in furnace and this reduce oxidation rate of char particles for front or opposed firing.

The capacity of each staging air part such as OAP, SAP and IAP can be determined with margin for the worst coal or NOx emission among various kinds of coal to be fired, in accordance with the guarantee or operational value of NOx emission and unburned combustible in fly ash. The worst coal can be evaluated on the basis of many field data in other practical boilers and test furnaces, and it can be mainly estimated by the coal property such as fuel ratio and the amount of fuel nitrogen determined by conventional proximate/ultimate analysis. And then, we also evaluate NOx emission and unburned combustible in fly ash for all coals to be fired in considerations of operational variables such as control damper openings and flue gas O_2 setting. Quantity of staging air will be controlled in accordance with the balance of air pressure drop through burners with individual seperate duct and through the staging air port with air duct. Staging air flow can be adjusted by control damper, however, air pressure drop through burners can be also effected by the quantity of primary air which depend on size distribution, grindability and moisture content of raw coal. Therefore some margine of capacity for each staging air will be necessary with considerations for the variation of raw coal property.

On designing low NOx furnace with INPACT method, the residence time, in reducing region determined by OAP location, is dominant factor on NOx emission. Fig. 9 shows NOx emission index as relative value of NOx emission for the dimensionless residence time on standard furnace design, along with coal property as fuel ratio. This relationships was also obtained by several field data on practical boilers and test furnace mentioned above. NOx emission can be easily estimated by base NOx value without any staging air flow and by NOx reduction rate corresponded with residence time in reducing region and staging air rate, the effect of which on NOx reduction also depends on residence time and is expressed such as in Fig. 7. Base NOx emission with low NOx burner can be also estimated in accordance with volatile-N and char-N and their conversion rate from fuel-N to NO in addition to thermal NOx, which is relatively lower emission but can be estimated burner zone liberation rate.

Next we introduce the results of field data on practical boiler adopted INPACT method. Fig. 10 shows the comparison of NOx emission between INPACT method and conventional air staging for both of a 410 T/h front firing and a 600 MW opposed firing boilers. 35% of NOx reduction was obtained by INPACT method and less than 150 ppm of NOx were realized for both boilers. This shows that INPACT method is applicable for wall firing boilers.

On the 600 MW boiler, we also studied the effectiveness of flue gas O_2 on NOx reduction for three (3) kinds of coal as shown in Fig. 11. By lowering flue gas O_2 to around 3%, NOx was remarkably reduced to less than 100 ppm under five (5) mill operation at full load, with satisfactory unburned combustible of less than 5% in fly ash. In this figure, it is also shown the comparison of NOx emission both for six (6) mill and five (5) mill operation. Number of mill in service can be decided by the carolific value of raw coal and consequently five mill operation gave more effective on NOx reduction with burner cut for top row of furnace rear side. This phenomena was recognized to be due to expanding residence time by burner cut of top row. These results were also achieved by SAP air feed in addition to OAP air staging as shown in Fig. 12, in which NOx was reduced by increasing SAP air damper opening. In this case, unburned combustible was still kept constant and this shows the effectiveness of SAP air feed on NOx reduction and control of unburned combustible in fly ash.

It was confirmed that IAP air injection also give an another effect on further improvement of unburned combustible reduction while NOx emission was still constant or less as shown in Fig. 13. According to the above results, we proved the effectiveness of each multiple air staging port such as OAP, SAP and IAP with INPACT method on NOx reduction and control of unburned combustible in fly ash.

Next, we also checked the applicability of INPACT method for various kinds of coal. With the agreement of local government on NOx emission of less than 170 ppm, we tested more than ten (10) coals ranked from 1.3 to 2.1 as fuel ratio and from 1.1 to 2.5 as fuel-N (d.a.f), with little adjustment of operating variables such as OAP control damper opening and flue gas O_2 setting to realize high efficiency operation under six mill operation. The results were shown in Fig. 14 and it was confirmed that NOx emission of all coals tested were around 125 - 150 ppm with satisfactory unburned combustible in fly ash. This proved that INPACT method was practical to control NOx emission for various kinds of foreign coals.

Finally, we introduce the comparison of performance on low NOx furnace. We usually evaluate NOx emission performance with unburned combustible in fly ash. Fig. 15 shows performance comparison of three kinds of furnace burned same brand coal. A boiler shows the furnace with INPACT method, B boiler with conventional air staging for foreign coals design, C boiler with conventional air staging for Japanese domestic coal design. For same unburned combustible in fly ash around 5%, INPACT method was very effective on NOx reduction and could realize less than 100 ppm. We also compared this method with reburning technology and proved INPACT method to be more effective for NOx reduction on pulverized coal firing.

CONCLUSION

We introduced the INPACT method to realize very low NOx emission less than 150 ppm or 100 ppm. INPACT method have been developed in accordance with fundamental experiments using by electrically heated flow reactor, small and large scale test furnace. This technology is the method to use multiple air staging with OAP, SAP and IAP so as to promote NOx destruction characteristics under fuel rich condition. We indicate the effectiveness of OAP location corresponding to the residence time, SAP air and IAP air on NOx emission and unburned combustible in fly ash. Previously, we also introduced the reburning technology(6)(7), however, INPACT method is more effective, economical and easier than that system.

This work described in this paper was not funded by the U.S. Environmental Protection Agency and therefore the contents do not necessarily reflect the view of the Agency and no official endorsement should be inferred.

References

(1) J.H.Phol, A.F. Sarofim ; Devolatilization and Oxidation of Coal Nitrogen, 16th symp.(Int.) on Combustion,1976.

(2) J.W. Glass, J.O.L. Wendt ; Mechanism Governing the Destruction of Nitrogeneous Species during Fuel Rich Combustion of Pulverized Coal, 19th Symp.(Int.) on Combustion, 1982.

(3) A.M. Hansen, H.Ikebe ; Significant Developments to limit NOx Formation in Steam Generator, 1979 Joint Power Generation Conference, 1979.

(4) N.S. Harding, L.D. smoot, P.O. Hedman ; Nitrogen Pollutant Formation in a Pulverized coal Combustior-Effect of Secondary Stream Swirl, AIChE J. Vol.28 No.4, 1982.

(5) J.O.L. Wendt, D.W. Pershing, J.W. Lee, J.W. Glass ; Pulverized Coal Combustion-NOx formation Mechanisms under Fuel Rich and Staged Combustion Conditions, 17th Symp. (Int.) on Combustion, 1978.

(6) S.Miyamae, H.Ikebe, K.Makino, K.Suzuki, J.Mogi ; Evalvation of IN-furnace NOx Reduction, 1985 Joint Symposium on Stationary Combustion NOx Control, 1985.

(7) S.Miyamae, T.Kiga, H.Ikebe, K.Suzuki ; Experimental Study on NOx Destruction Characteristics by Reburning of Pulverized Coal, 1986 Fall Meeting of Western State Section/The Combustion Institute, 1986.

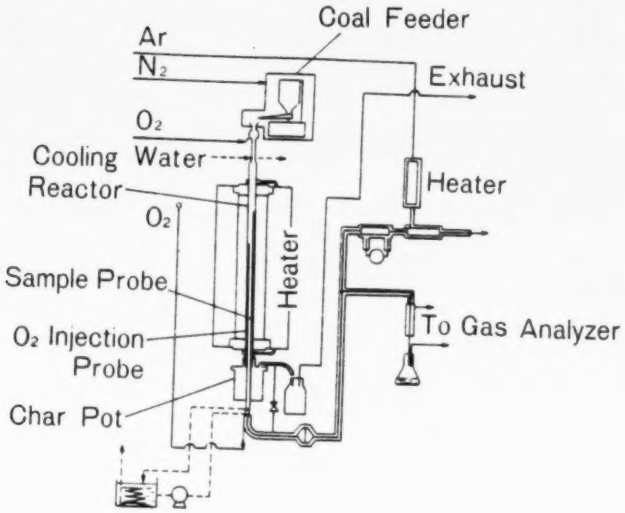

Coal Feeder
Ar
N₂
Exhaust
O₂
Cooling Water
Reactor
Heater
O₂
Heater
Sample Probe
To Gas Analyzer
O₂ Injection Probe
Char Pot

Fig.1 Schematic Flow Diagram of Electrically Heated Flow Reactor

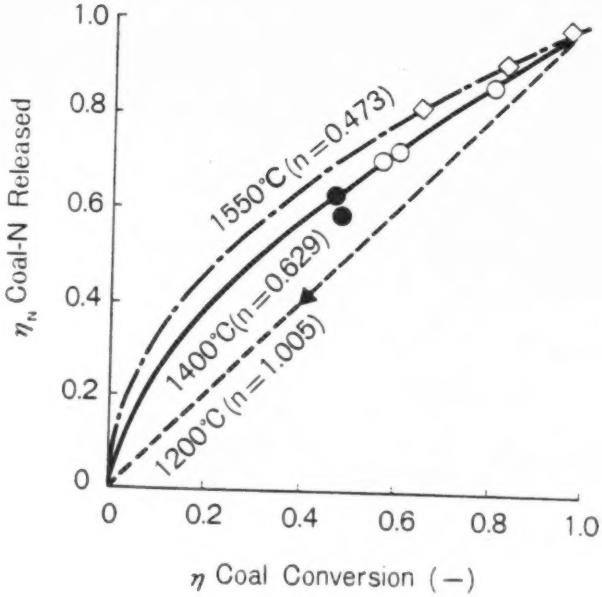


Fig. 2 Effect of Temperature on Coal-N Released.

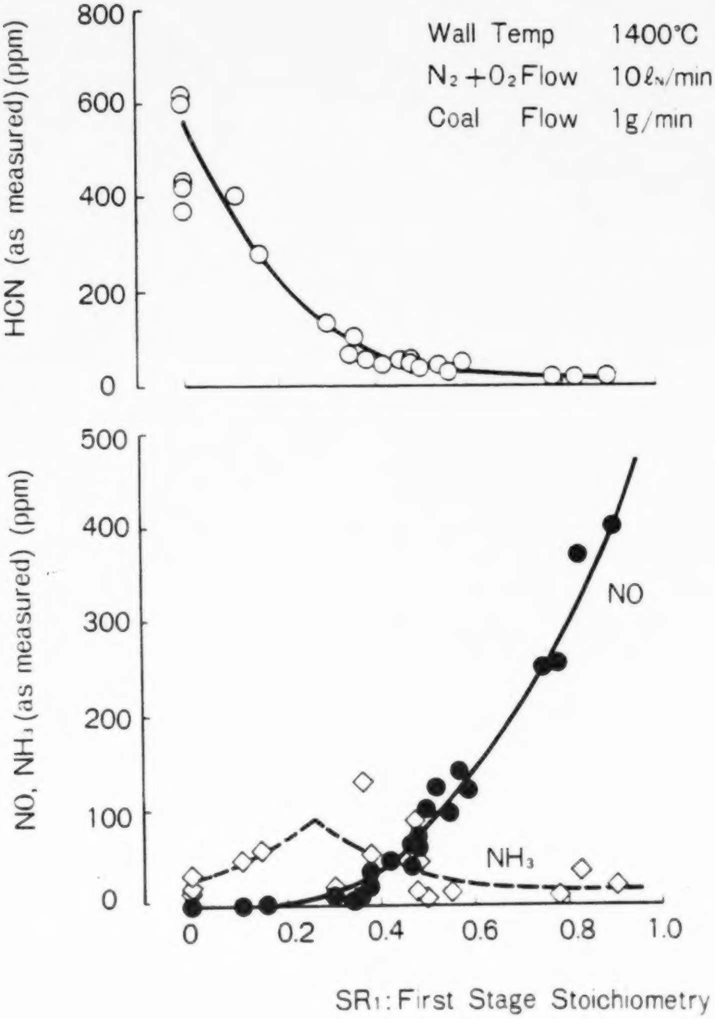


Fig. 3 Formation of Nitrogeneous Species during Fuel Rich Combustion

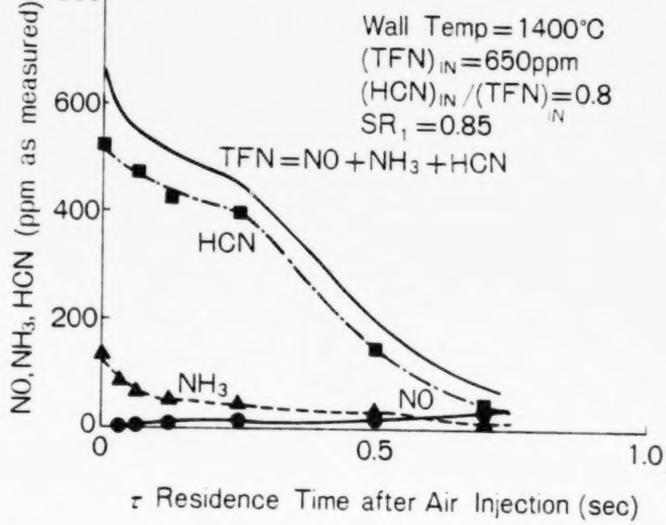


Fig. 4 Effect of Residence Time on The Destruction of Nitrogeneous Species

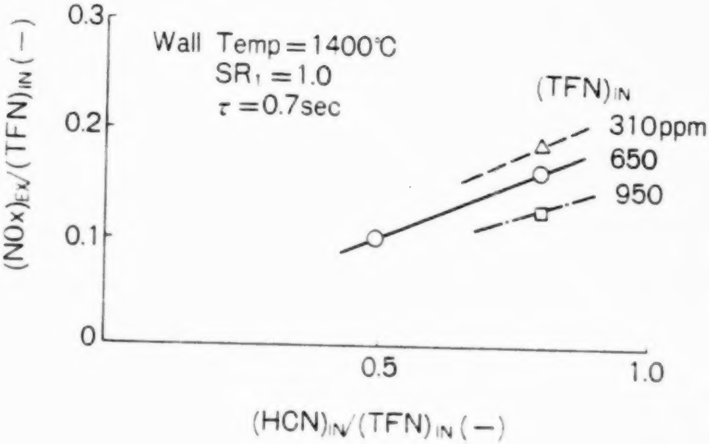


Fig. 5 Effect of HCN Content in Volatile-N on NOx Formation with Staging Air

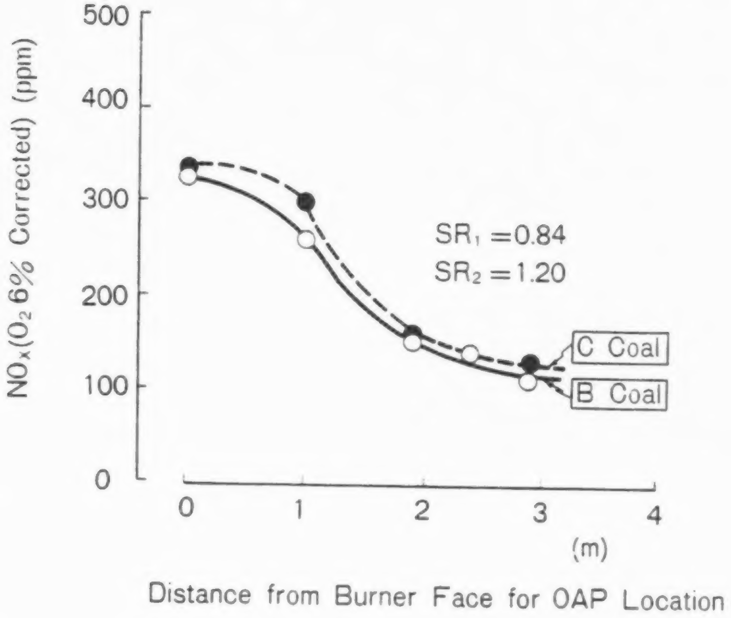


Fig. 6 Effect of Over-Fire Air Port Location on NOx Emission

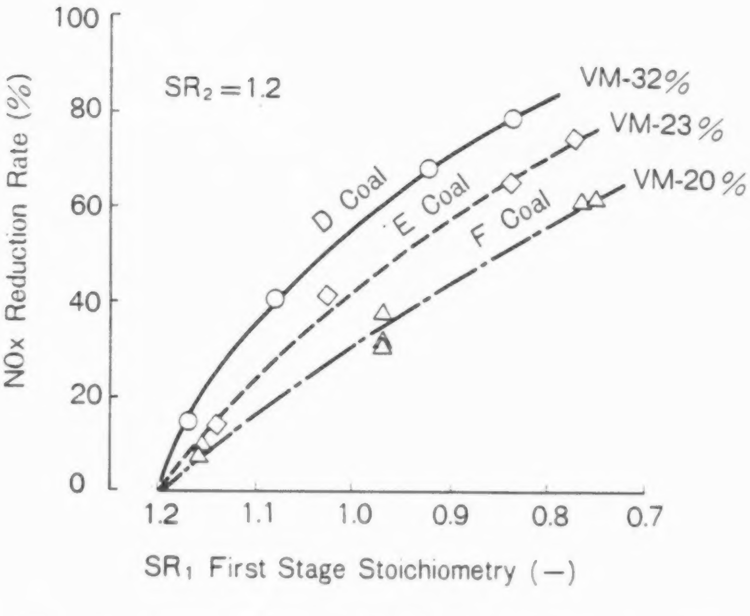


Fig. 7 Comparison of NOx Reduction by SR1 for Various Volatile Coals

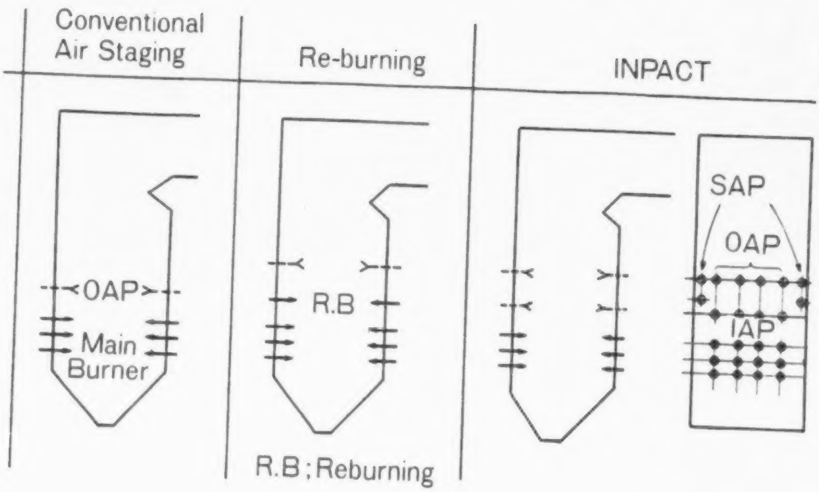

Conventional Air Staging
Re-burning
INPACT
OAP
Main Burner
R.B
R.B; Reburning
SAP
OAP
IAP

Fig. 8 Comparson of Low NOx Furnace

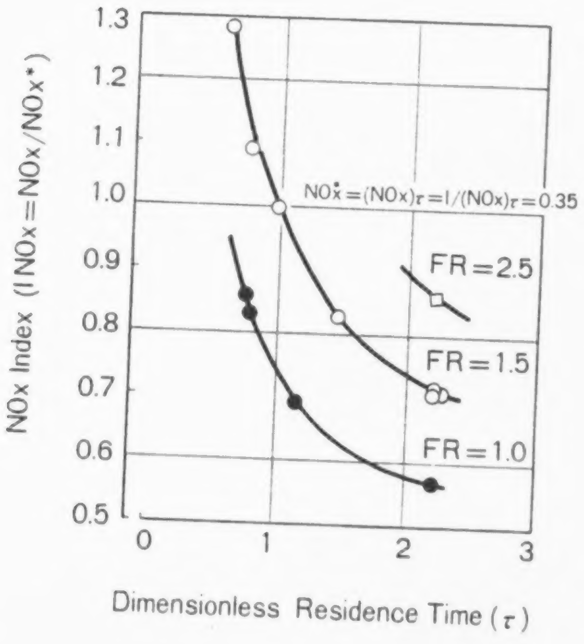


Fig. 9 Effect of Residence Time in Reducing Region on NOx Reduction

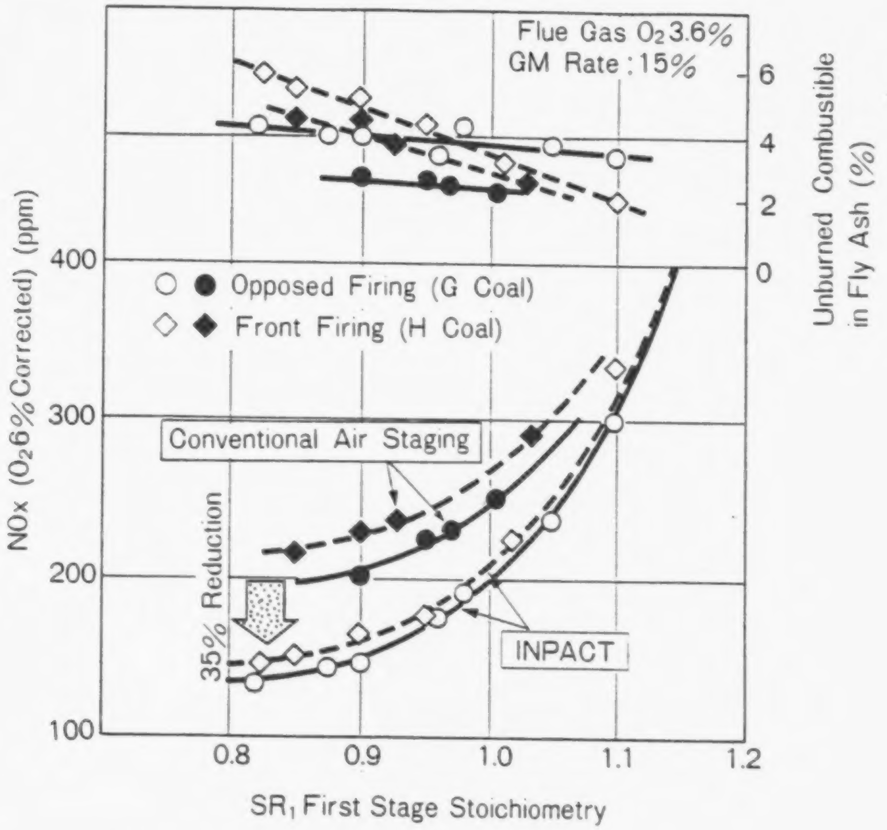


Fig. 10 Comparison of NOx Emission

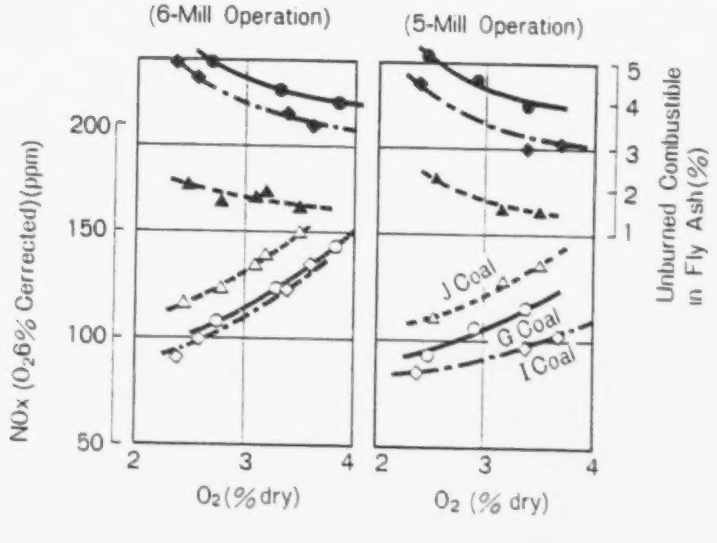


Fig. 11 Effect of Flue Gas O_2 on NOx Emission With INPACT Method

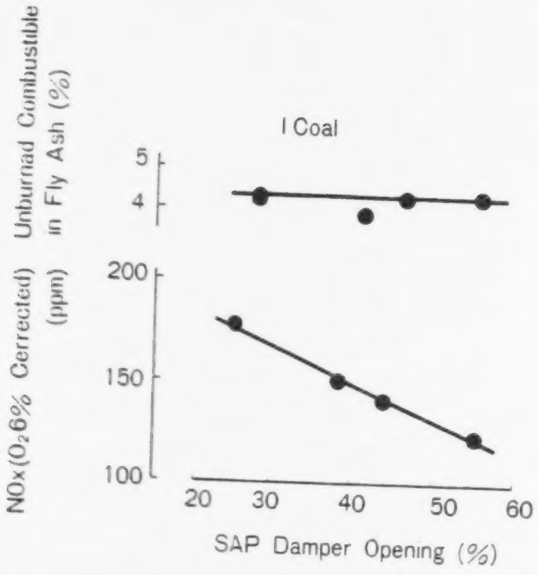


Fig. 12 Effect of SAP Air with INPACT Method on NOx Emission

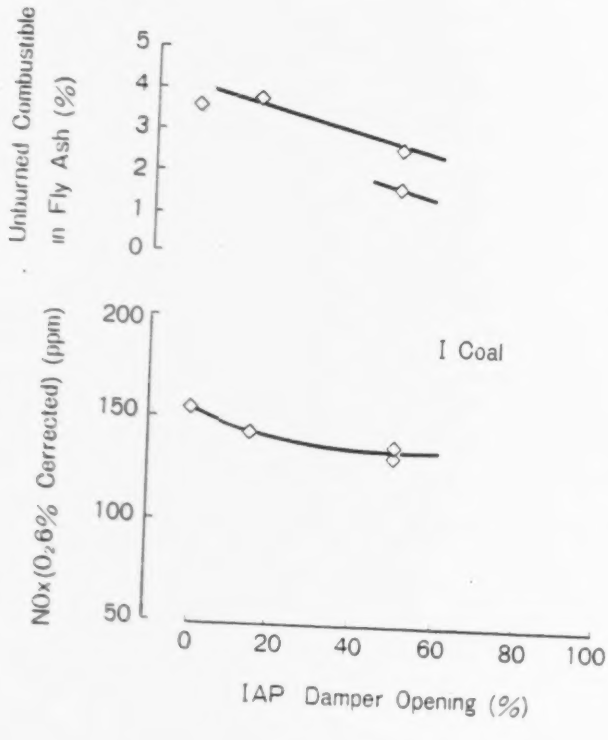


Fig. 13 Effect of IAP Air with INPACT Method on NOx Emisson and Unburned Combustible in Fly Ash

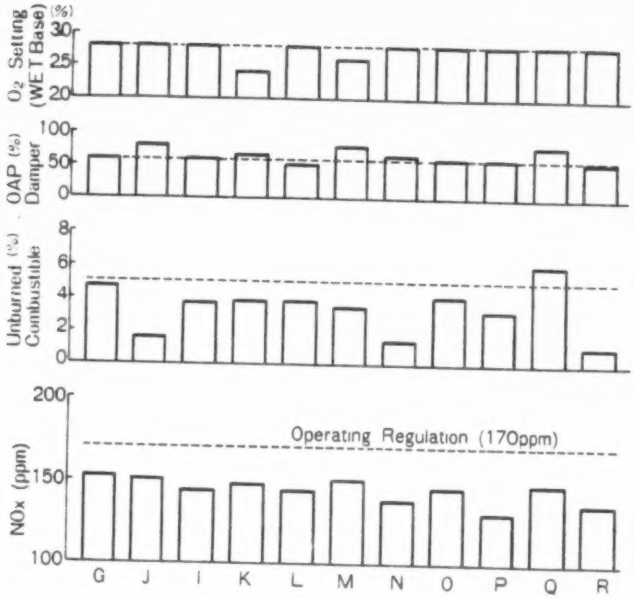


Fig. 14 Comparison of Various Kinds of Coal (at 600MW 6Mill Operation Basis)

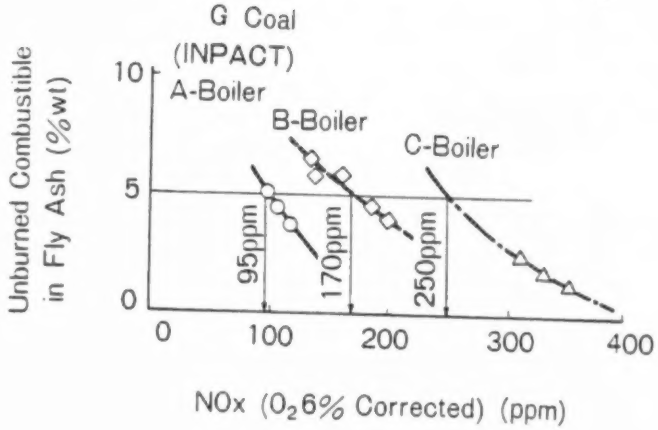


Fig. 15 Comparison of Furnace Performance on NOx Emission and Unburned Combustible in Fly Ash.

Table. I ANALYSIS METHOD OF SPECIES

Spocies	Method of Analysis	Type of Analyzer (Column Pack Agent)	Determination Lower Limit
NOx	Chemiluminescent	HORIBA ENDA-C211	2 ppm
HCN	Gas Chromatograph	SHIMAZU GC-7A (FTD) (Porapak Q)	0.1 ppm
NH_3	Gas Chromatograph	SHIMAZU GC-7A (FTD) (Chromosorb 103)	1 ppm
H_2,O_2,N CH_4, CO	Gas Chromatograph	SHIMAZU GC-4BIT (TCD) (MS-SA)	20 ppm
CO	Gas Chromatograph	SHIMAZU GC-6A (TCD) (Porapak Q)	20 ppm
CxHy	Gas Chromatograph	SHIMAZU GC-6AM (FID) (Silicone OV-101)	1 ppm
T-HC	THC Monitor (FID)	YANAGIMOTO EHF-1001	1 ppm as CH_4 Basis

Table 2 Coal Property

Coal Name	A	B	C	D	E	F	G	H	I
I.M (%)	3.7	3.7	3.2	7.4	2.1	3.8	3.7	2.5	3.5
V.M (%)	31.0	22.6	18.4	32.4	22.9	19.0	31.8	32.5	33.5
F.C (%)	49.8	63.7	65.0	49.7	57.7	63.0	50.5	50.0	50.7
Ash (%)	15.5	10.0	13.4	10.5	17.3	14.2	14.0	15.0	12.5
Ho (kcal/kg)	6,950	7,100	6,940	6,190	6,620	6,610	6,570	6,700	6,750
C (%)	71.0	77.1	75.1	70.3	70.7	73.1	70.3	68.4	71.8
H (%)	4.7	4.2	3.8	4.5	3.9	4.2	4.9	4.5	4.8
O (%)	6.3	6.2	5.0	12.9	6.1	6.9	8.7	9.0	8.7
N (%)	1.5	1.4	1.6	0.9	1.3	0.8	1.8	1.5	1.5
S (%)	0.5	0.7	0.8	0.1	0.3	0.2	0.3	1.5	0.8

Coal Name	J	K	L	M	N	O	P	Q	R
I.M (%)	3.7	5.7	3.6	2.6	4.0	2.5	2.5	3.6	7.0
V.M (%)	29.3	29.8	29.1	26.3	34.4	34.3	30.7	27.9	33.6
F.C (%)	49.3	51.6	54.9	55.7	45.4	52.2	51.5	57.1	49.3
Ash (%)	17.7	12.9	12.4	15.4	16.2	10.8	15.3	11.4	10.1
Ho (kcal/kg)	6,340	6,510	6,860	6,670	6,320	7,210	6,700	6,840	6,250
C (%)	68.0	71.6	71.3	70.7	66.4	75.2	70.1	73.8	69.9
H (%)	4.5	4.3	4.8	4.1	4.6	4.7	4.5	4.2	4.5
O (%)	7.7	8.5	9.0	7.6	9.9	6.4	8.5	8.4	13.4
N (%)	1.6	1.6	1.6	1.4	2.0	2.2	1.0	1.5	0.9
S (%)	0.5	0.4	0.5	0.4	0.2	0.2	0.1	0.3	0.2

I.M Inherent Moisture V.M Volatile Matter
F.C Fixed Carbon Ho Heating Value

GAS REBURNING-SORBENT INJECTION - A COMBINED NO_x/SO_x CONTROL TECHNOLOGY

by: W. Bartok, B. A. Folsom
Energy and Environmental Research Corporation
Irvine, California 92718

and

F. R. Kurzynske
Gas Research Institute
Chicago, Illinois 60631

ABSTRACT

Gas Reburning-Sorbent Injection (GR-SI) involves co-firing pulverized coal with natural gas in combination with sorbent injection and/or coal cleaning to allow for cost effective reduction of acid rain precursor emissions (NO_x and SO_x) from pre-NSPS coal fired utility boilers. This would provide the utility industry with flexibility in fuel selection to satisfy potential acid rain control legislation. This paper describes a demonstration project which will be cooperatively funded by the Department of Energy, the Gas Research Institute and the State of Illinois Department of Energy and Natural Resources, to demonstrate GR-SI on three coal fired utility boilers located in the State of Illinois. Gas Reburning-Sorbent Injection will be applied to one each of wall, corner and cyclone fired boiler types with overall reduction targets of 60% in NO_x and 20% in SO_x emissions. The overview of the planned demonstration project will be discussed, including design consideration and economic projections for GR-SI applications.

The work described in this paper was not funded by the U.S. Environmental Protection Agency and therefore the contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

INTRODUCTION

The cost of power generation from existing pulverized coal fired steam generating plants is strongly dependent upon coal quality and the requirements for environmental controls. Coal is not a pure hydrocarbon, it contains mineral matter, sulfur and nitrogen. Some impurities can cause operational problems due to slagging, fouling, erosion and corrosion which affect the availability and maintainability of the plant and consequently the cost of power. The impurities found in coal are converted to atmospheric pollutants during combustion. Mineral matter forms fly ash, sulfur is oxidized to sulfur dioxide and organically bound nitrogen is converted in part to nitric oxides. Acid precipitation in certain parts of the United States and Canada has been attributed to emissions of sulfur dioxide and nitric oxide from coal fired power plants. Proposed legislation to reduce the emission of these acid rain precursors will:

- Increase the cost of power due to the addition of air pollution control devices,
- Increase the use of low sulfur coals, thereby reducing the demand for Eastern and Midwestern coals.

Consequently, there is a need for a low cost, retrofit acid rain precursor control technology which will provide the electric utility industry with the option to use local coals. Gas Reburning-Sorbent Injection is one such technology.

GAS REBURNING-SORBENT INJECTION

Gas Reburning-Sorbent Injection (GR-SI) is an integration of two developmental technologies: reburning for NO_x control in conjunction with sorbent injection for SO_x control. GR-SI is a retrofit technology with applicability to all types of coal fired boilers. A schematic showing the application of GR-SI to a corner fired boiler is illustrated in Figure 1. Gas reburning involves the injection of natural gas above the main heat release zone to reduce the nitric oxide formed to molecular nitrogen. Low cost calcium based sorbents can be injected at one or more locations as the combustion gases pass from the radiant furnace, through the convective passes to the air heater.

Reburning

The concept of NO reduction by flames has been recognized for over a decade. A flue gas incinerator was developed by the John Zink Company (1), and Sternling, Wendt and Mattovich (2) found that NO could be reduced in laboratory flat flames by injecting methane into the combustion products. Reburning for in-furnace NO_x control has been applied to boilers in Japan (3,4) and work is being supported in the United States by the EPA and EPRI as well as GRI (5,6,7). Reburning denotes a process in which a fraction of the fuel bypasses the main heat release zone and is injected above the main burners to provide the fuel for reburning. The overall process can be divided into three zones:

1. Main Heat Release Zone: Approximately 80-85 percent of the heat is released in this zone under fuel lean conditions producing nitric oxide together with products of combustion which form the input to the reburning zone. In addition, if sufficient residence time is not provided in the main heat release zone, unburned fuel fragments may leave this zone and enter the reburning zone.

2. Reburning Zone: The reburning fuel (normally 10 to 20 percent of the total fuel input to the boiler) is injected downstream of the

primary zone to create a fuel rich, NO_x reduction zone. Nitric oxide formed in the main heat release zone reacts with the hydrocarbon fragments formed during the oxidation of the reburning fuel, primarily CH species, to produce intermediate species such as HCN and NH_3, and the nonpollutant species, N_2.

3. Burnout Zone: In the third and final zone, air is added to produce overall lean conditions and to oxidize all remaining fuel fragments. The remaining reduced nitrogen species (NH_3 + HCN) will either be oxidized to NO or reduced to molecular nitrogen.

The major process parameters which control the efficiency of the reburning process are the stoichiometry, temperature and residence time of the reburning zone.

Bench and pilot scale studies have been carried out at EER to establish the optimum process parameters for the reburning process. The parameters of interest are the fuel type, stoichiometry and exit NO level for the main heat release zone, the amount of reburning fuel and the residence time in the reburning zone, and the temperature and overall excess oxygen level in the burnout zone. Figure 2 illustrates some of the key results from the parametric studies. The effectiveness of reburning increases as the excess oxygen level in the main heat release zone is reduced (Figure 2a). Under residence time conditions typical of field practice, a reburning fuel which does not contain bound nitrogen is most effective and the fractional reduction in NO_x emissions is independent of the NO concentration entering the reburning zone above approximately 300 ppm (Figure 2b). The temperature at which burnout occurs is also an important process parameter (Figure 2a). Pilot scale studies have also been carried out to establish the importance of effective mixing in both the reburning and the burnout zones.

The performance of natural gas reburning when applied to coal fired furnaces was examined by EER in terms of NO_x, SO_2 emissions and combustion efficiency. Experiments were carried out in both a pilot scale, 3 MW_t (10 x 10^6 Btu/hr) furnace with inside dimensions 122 x 122 x 762 cm (4 x 4 x 25 ft) and a small, 300 kW_t (1 x 10^6 Btu/hr) refractory-lined furnace with an inside diameter of 56 cm (22 inches). A high sulfur Illinois coal was fired in the primary zone with the reburning fuel, natural gas or Illinois coal, and burnout air was injected at 1622K (2460°F) and 1489K (2220°F), respectively. Exhaust gas and solid samples were extracted from the furnace at 1144K (1600°F). As shown in Figure 3a, NO_x emissions decreased dramatically as the reburning fuel was added with the total load maintained at 1.0 x 10^6 Btu/hr. These experiments were run at an SR_1 of 1.0 for three different reburning fuel loads, and in each case, natural gas proved to be a better reburning fuel than coal. Similar results were also obtained in the pilot scale furnace.

Figure 3 also shows analogous plots for CO emissions and percent carbon retained in the ash. Coal reburning is shown by the solid symbols and gas reburning by the open symbols. Again, natural gas was the better fuel for minimizing CO emissions and percent carbon in ash. For natural gas, increasing percent reburning fuel actually decreases CO emissions while for coal, carbon content in the ash was increased.

Sorbent Injection

As shown in Figure 1, the reburning process can be combined with sorbent injection for SO_2 control. The burnout airstream can be used as a carrier for the sorbent medium for both reburning and sorbent injection. It is important to mix the burnout air and the sorbent as quickly and effectively as possible. The design requirements of both processes are similar.

The use of calcium-based sorbents with furnace injection for SO_2 control has been studied extensively. The process involves calcination of a calcium-based sorbent, which may be either a carbonate or hydrate, producing calcium oxide. This calcium oxide reacts with SO_2 in the sulfation zone producing solid calcium sulfate which can be removed together with the flyash in an electrostatic precipitator or bag filter. Two major parameters control the utilization of the calcium in the sorbent and thus the cost effectiveness of the process. These are:

- The reactivity of the calcium oxide formed by calcination. This is strongly dependent upon the surface area of the calcine which is a function of the sorbent type and the thermal history of the calcine. Reactivity tends to decrease as the sorbent particle temperature is increased due to grain growth.

- The residence time of the calcine under conditions conducive to sulfation. Significant sulfation cannot occur above approximately 1500K (2250°F) and the rate of sulfation becomes negligible below approximately 1140K (1600°F). Thus, the residence time of the active particle within this temperature window is important in the sulfur capture process.

Figure 4 summarizes pilot scale data obtained by EER, which illustrate the potential of GR-SI for combined NO_x/SO_x control. These data indicate that 60 percent NO_x reductions can be achieved from typical pre-NSPS NO_x levels. Sulfur dioxide reductions in excess of 50 percent can be achieved by combining reburning with sorbent injection, if a hydrated sorbent is used. These data are typical of those obtained with optimized Gas Reburning-Sorbent Injection for a wide spectrum of primary fuels and they appear to be generally achievable in full scale systems.

Overview of Planned Demonstration Project

EER plans to conduct a cooperatively funded project at three host utility sites to demonstrate the technical feasibility and cost effectiveness of GR-SI. The funding project participants will be the DOE, the GRI, and the State of Illinois ENR. The project will be divided into three phases, as follows:

- Phase I - Design and Permitting. This initial phase will culminate in the detailed design of gas reburning and sorbent injection systems for each of three host sites. A program plan will be prepared for the equipment construction and demonstration testing. An industry panel will be established to initiate technology transfer.

- Phase 2 - Construction and Startup. Following approval by the funding participants, the gas reburning and sorbent injection equipment will be installed and checked out at each host site. The process and engineering designs will be presented to the industry panel.

- Phase 3 - Operation, Data Collection, Reporting and Disposition. Each host unit will be tested over a range of conditions with several U.S. coals, culminating in one-year long-term evaluations. The results will be compiled into a guideline manual which will be made available to industry. The project results will be presented to the industry panel.

The demonstration of GR-SI is not intended as the first generation of a specific technology, but rather it will build upon the results of several individual technology demonstrations now being conducted by the EPA and others. The focus of this program is to demonstrate the application and performance of a combined technology which will allow cost effective control of acid rain precursors. A major feature of the program is that GR-SI will be demonstrated on all three types of coal fired boilers which are typical of pre-NSPS designs (i.e., wall, corner, and cyclone fired units).

EER's technical approach is illustrated schematically in Figure 5. Each host site will be considered separately, based on its unique design parameters,operating history and performance requirements. These factors will be evaluated by reviewing historical operating and performance data and plant design specifications. A field test will be conducted to quantify performance and emissions over the normal duty cycle. We will consider several alternative and complimentary technologies: gas reburning for NO_x control, a range of approaches to sorbent injection for SO_2 control, and coal cleaning. A technology combination will be selected for each site which meets the emissions control and performance objectives at minimum total cost. This process definition will include specification of all major components and projection of performance for each host site. Following DOE approval, EER will proceed with the detailed design. This will include complete construction plans including drawings, equipment specifications, cost estimates and construction schedules. All necessary permits will be obtained. Phase 1 will culminate in the preparation of a comprehensive program plan. It will detail the design and performance projections for the equipment to be installed at each of the three host sites, present construction plans and propose a demonstration plan for quantifying the performance at each host site.

Table 1 summarizes the characteristics of each unit and presents the preliminary approach to optimization of the GR-SI technology. The three proposed host sites are small utility boilers now in commercial operation in the State of Illinois. All fire Midwest bituminous coals and are equipped with cold side electrostatic precipitators for particulate emission control. These units differ in several significant respects:

- Firing configuration and capacity
- Electrostatic precipitator size
- Fuel characteristics
- Emission constraints

As planned, the program will be completed in four years.

Cost and Benefits of GR-SI

Figure 6 shows the cost effectiveness of various SO_x control technologies. It can be seen that GR-SI allows both a greater reduction in SO_2 and is as cost effective as LIMB. Only LIMB with low NO_x burners and GR-SI provide both SO_x and NO_x control. Tables 2 and 3 present the basis for these cost comparisons. As shown in Table 2, a 500 MW_e wall fired boiler was assumed, with NO_x and SO_x emission reduction targets of 60% and 50%, respectively. It was assumed that 15% of the total heat input would result from gas co-firing, with a gas fuel premium of M$ 1.0 and M$ 2.0, relative to coal. The superior cost effectiveness of GR-SI over flue gas desulfurization is shown in Table 3, keeping particularly in mind that GR-SI is a combined NO_x/SO_x emission control technology.

To sum up, a successful demonstration program will establish the following benefits of GR-SI technology:

- NO_x emissions can be reduced by 60 percent. This can be achieved without the need for modifications to the original firing equipment, thus eliminating problems associated with retrofitting low NO_x burners. Gas is ideal as a reburning fuel because it can be distributed evenly, it is more effective in reducing NO_x than coal and requires less residence time in the reburning zone.
- SO_x emissions can be reduced by 50 percent and because the two technologies are combined the burnout air can be used as a sorbent transport medium.
- The sorbent requirements to provide a given reduction in SO_2 emissions are reduced in direct proportion to the amount of gas co-firing. This reduces the load on the particulate control devices.
- Gas reburning can be applied in conjunction with various sorbent injection technologies such as in-furnace or duct injection as well as with coal cleaning.
- GR-SI provides electric utilities with flexibility in coal selection to meet acid rain control legislation.
- GR-SI has the potential to improve the operability of some pulverized coal fired boilers.
- GR-SI can be retrofitted to pre-NSPS wall, corner and cyclone fired boilers. These units produce 12 million tons of SO_2 per year in the U.S.

REFERENCES

1. Reed, R. D. Process for the Disposal of Nitrogen Oxide. John Zinc Company, U.S. Patent 1,274,637, 1969.

2. Sternling, C. V., J. O. L. Wendt, and M. A. Mattovich, Fourteenth Symposium (International) on Combustion, p. 897, The Combustion Institute, 1973, p. 897.

3. Takahashi, Y., et al. Development of Mitsubishi "MACT" In-Furnace NO_x Removal Process. Presented at U.S.-Japan NO_x Information Exchange, Tokyo, Japan, May 25-30, 1981.

4. Okigami, N., et al. Multistage Combustion Method for Inhibiting Formation of Nitrogen Oxides. U.S. Patent 4,395,223, 1983.

5. Greene, S. B., S. L. Chen, W. D. Clark, M. P. Heap, D. W. Pershing, and W. R. Seeker. "Bench-Scale Process Evaluation of Reburning and Sorbent Injection for In-Furnace NO_x/SO_x Reduction." EPA-600/7-85-012, March, 1985.

6. Greene, S. B., S. L. Chen, D. W. Pershing, M. P. Heap, and W. R. Seeker. "Bench-Scale Process Evaluation of Reburning for In-Furnace NO_x Reduction." ASME Paper No. 84-JPGC-APC-9, 1984.

7. Seeker, W. R., et al. "Controlling Pollutant Emissions from Coal and Oil Combustors Through the Supplemental Use of Natural Gas." Final Report, GRI 5083-251-0905, 1985.

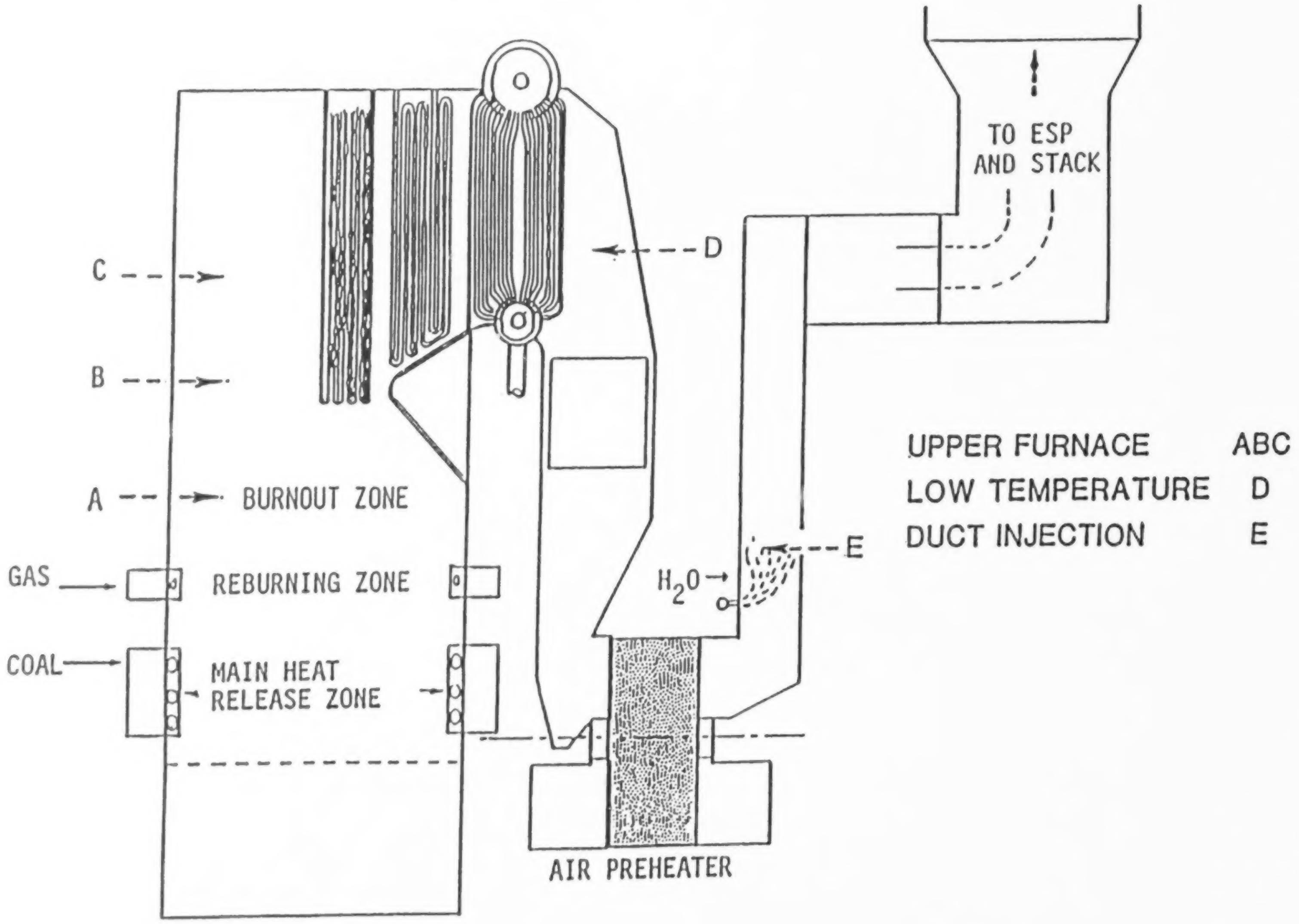
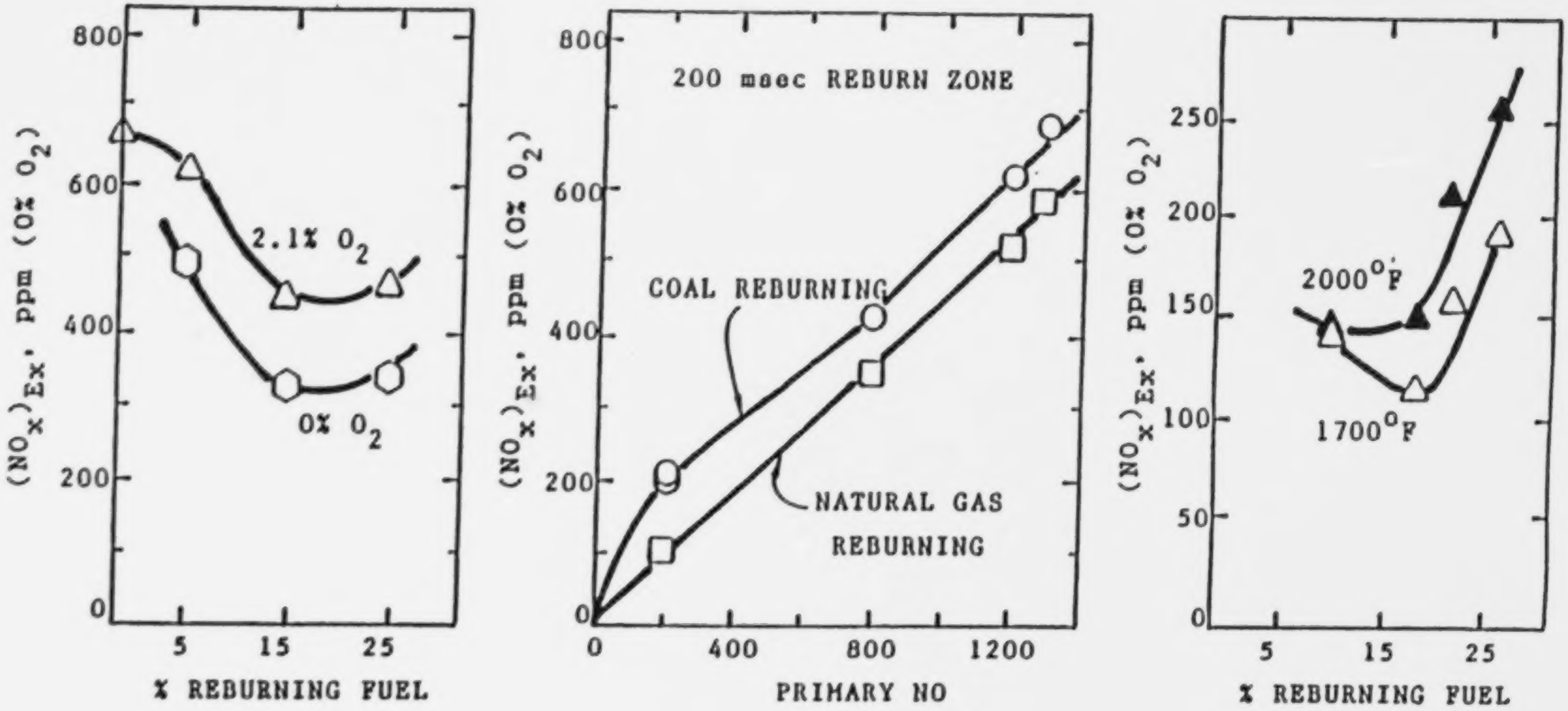

TO ESP
AND STACK
C
B
A
D
E
BURNOUT ZONE
GAS
REBURNING ZONE
COAL
MAIN HEAT
RELEASE ZONE
H_2O
AIR PREHEATER
UPPER FURNACE ABC
LOW TEMPERATURE D
DUCT INJECTION E

FIGURE 1. GAS REBURNING-SORBENT INJECTION TECHNOLOGY

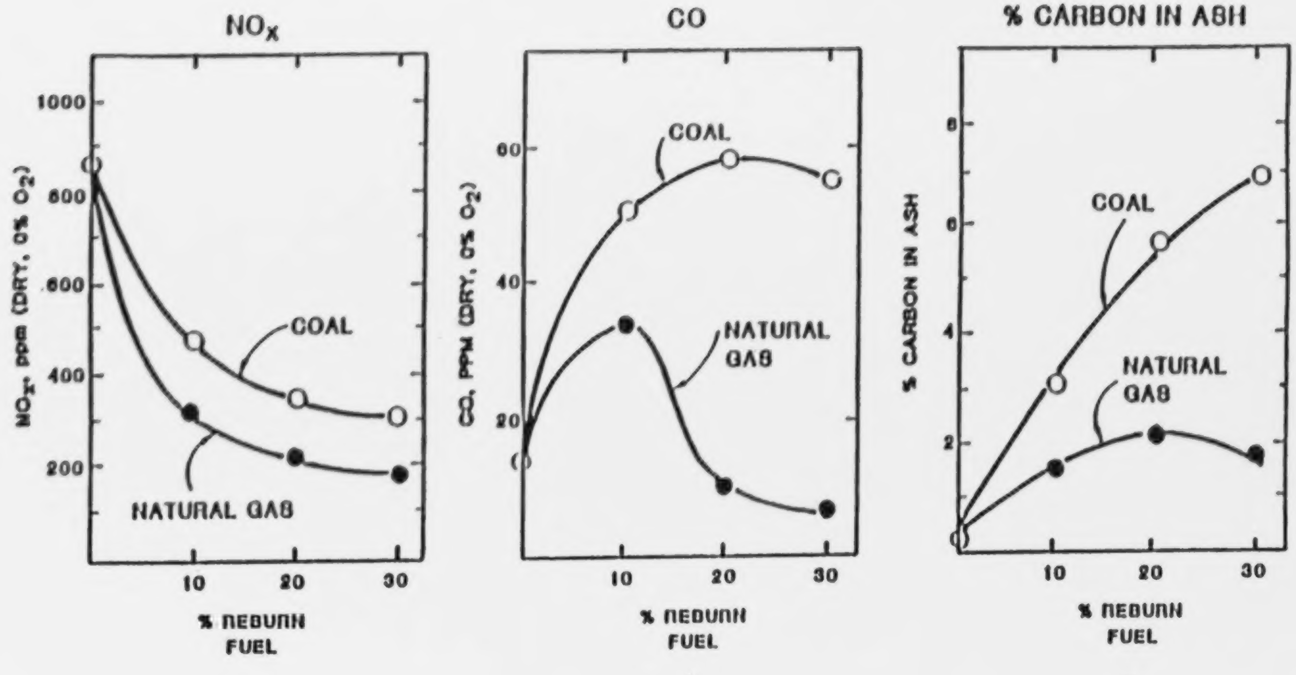


a. Main Heat Release Zone Excess O_2 Level

b. Initial NO Level and Reburning Fuel Type

c. Burnout Temperature

FIGURE 2. KEY PROCESS PARAMETERS FOR REBURNING



a. b. c.

FIGURE 3. BENEFITS OF NATURAL GAS REBURNING WHEN APPLIED TO COAL FIRED FURNACES

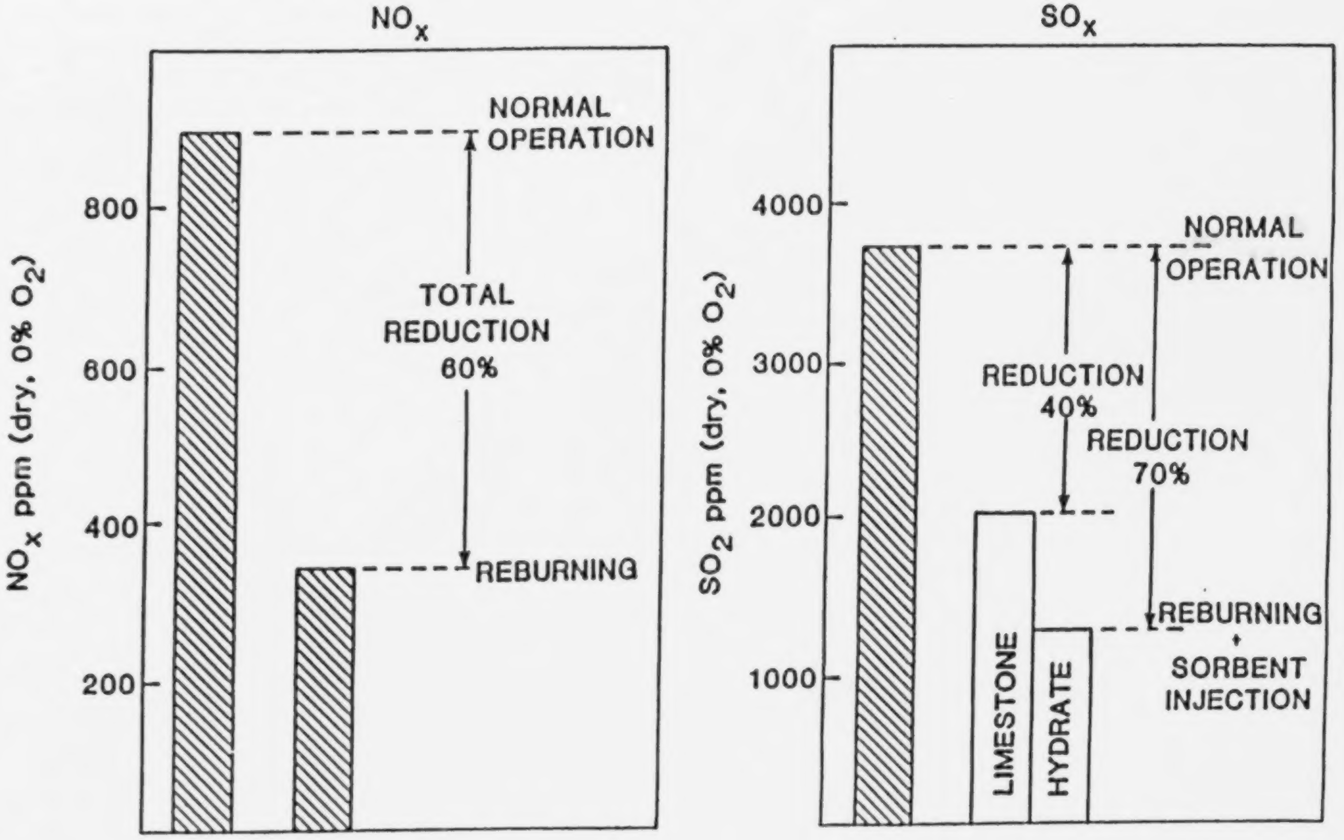


FIGURE 4. REDUCTION IN ACID RAIN PRECURSORS BY GR-SI

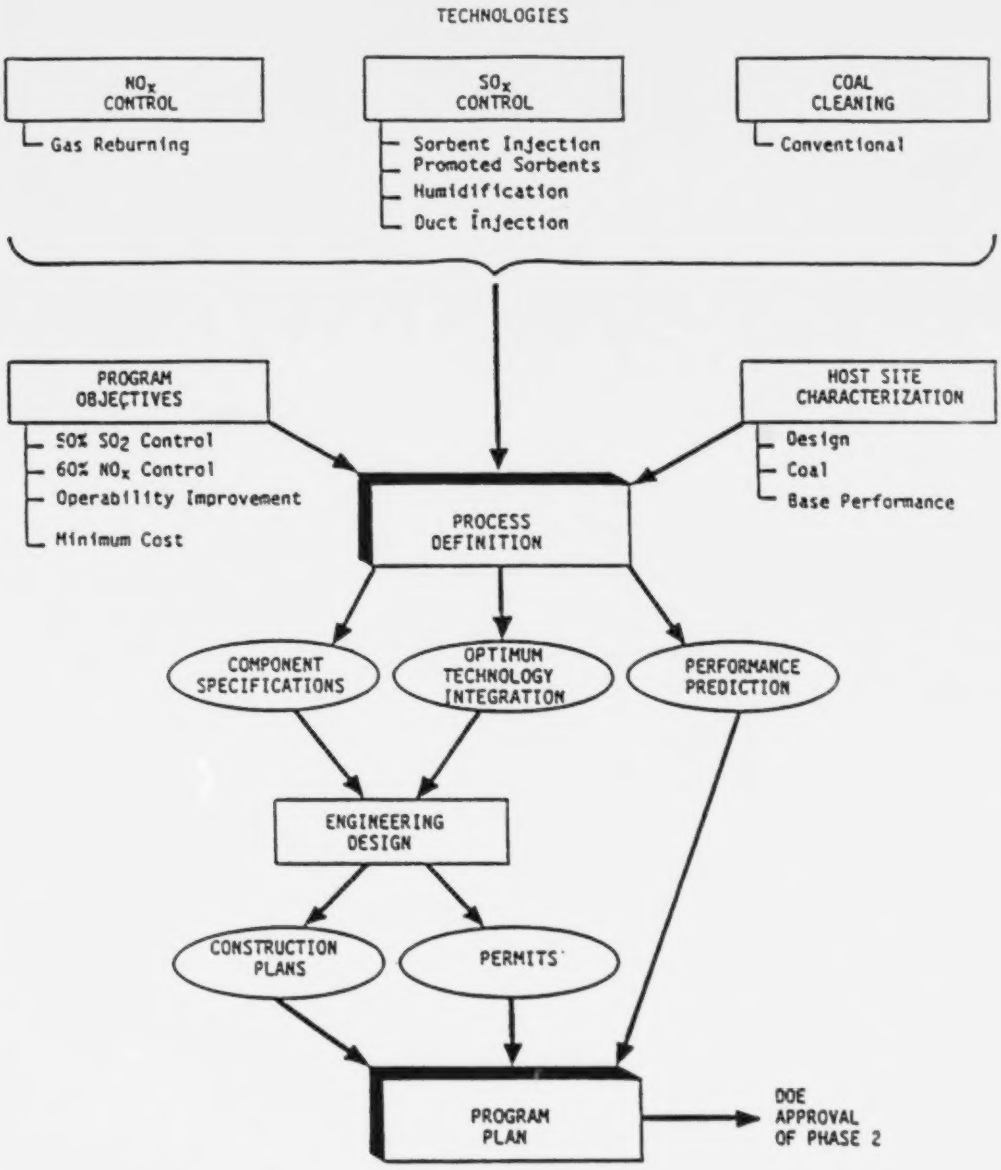

TECHNOLOGIES
NO_x CONTROL
Gas Reburning
SO_x CONTROL
Sorbent Injection
Promoted Sorbents
Humidification
Duct Injection
COAL CLEANING
Conventional
PROGRAM OBJECTIVES
50% SO_2 Control
60% NO_x Control
Operability Improvement
Minimum Cost
HOST SITE CHARACTERIZATION
Design
Coal
Base Performance
PROCESS DEFINITION
COMPONENT SPECIFICATIONS
OPTIMUM TECHNOLOGY INTEGRATION
PERFORMANCE PREDICTION
ENGINEERING DESIGN
CONSTRUCTION PLANS
PERMITS
PROGRAM PLAN
DOE APPROVAL OF PHASE 2

FIGURE 5. PHASE 1 - TECHNICAL APPROACH

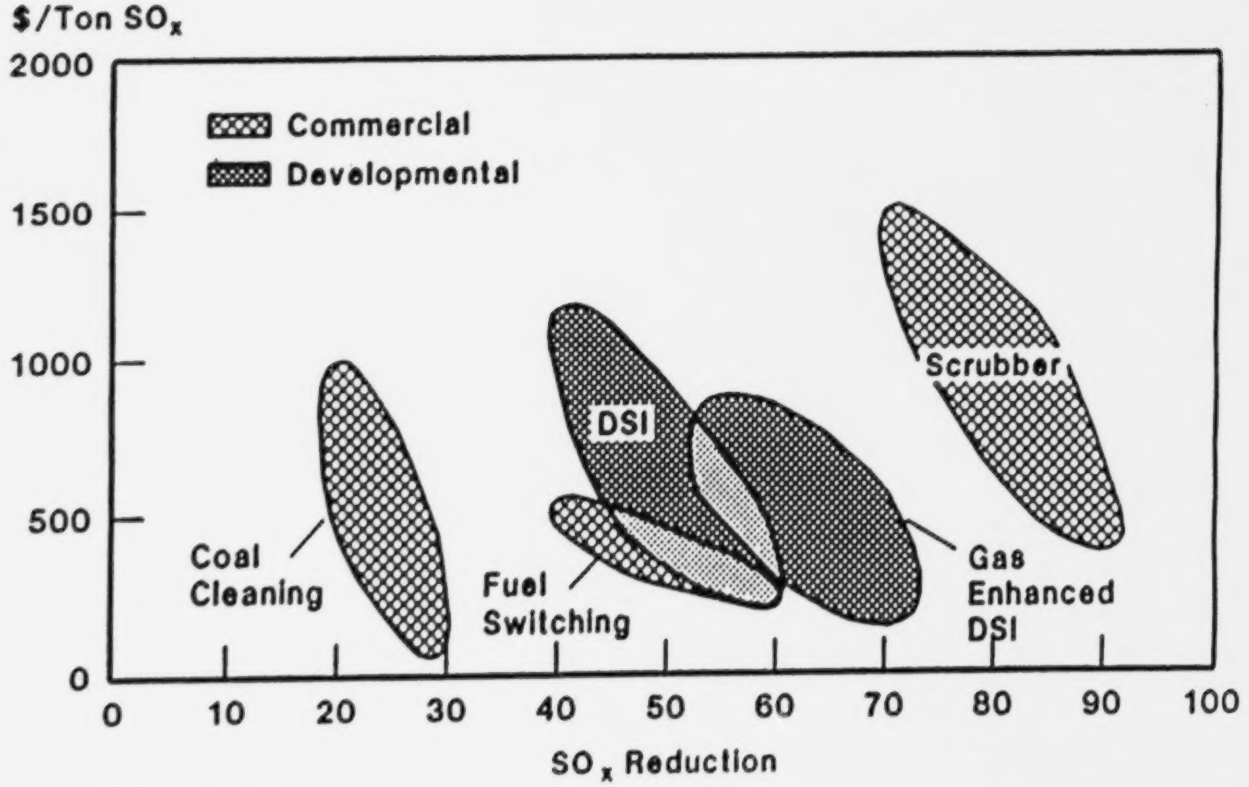


FIGURE 6. COST EFFECTIVENESS RANGES FOR ALTERNATIVE CONTROL STRATEGIES - SO_x

TABLE 1. CHARACTERISTICS OF HOST SITES

GENERAL			
UTILITY	ILLINOIS POWER	CILCO	CWLP
STATION, UNIT	HENNEPIN, 1	EDWARDS, 1	LAKESIDE, 7
LOCATION: STATE	ILLINOIS	ILLINOIS	ILLINOIS
CAPACITY .(MW)	80	117	40
BOILER			
FIRING CONFIGURATION	TANGENTIAL	FRONT WALL	CYCLONE
CAPACITY (10^3 lb/hr)	585	850	320
MANUFACTURER	CE	RILEY	B&W
PRECIPITATOR			
LOCATION	COLD SIDE	COLD SIDE	COLD SIDE
SIZE (SCA)	223	137	333-1000
MANUFACTURER	BUELL	AMERICAN STANDARD	SMIDTH
FUEL			
COAL TYPE	ILLINOIS, BIT	BLEND ILLINOIS, BIT KENTUCKY, BIT	ILLINOIS, BIT
SULFUR (%)	3-8	1.0	3.6
GAS AVAILABILITY	YES, 100%	4 MILES	ON SITE
EMISSIONS CONTROL APPROACH			
NO_x APPROACH	GAS REBURNING	GAS REBURNING	GAS REBURNING
CONTROL (%)	60	60	60
SO_2 APPROACH	UPPER FURNACE INJECTION	UPPER FURNACE INJECTION	DUCT INJECTION
CONTROL (%)	50	50	50
ESP ENHANCEMENT	HUMIDIFICATION	HUMIDIFICATION SO_3, INJECTION	NONE

TABLE 2. BASES FOR ECONOMIC COMPARISONS OF SO_x and SO_x/NO_x RETROFIT CONTROL TECHNOLOGIES FOR POWER PLANTS

500 MW Rated Capacity -- Wall-Fired Boiler

Capacity Factor = 0.6

Coal Characteristics: 2.5% Sulfur
12.5% Ash
11,500 Btu/lb

15-Year Levelization Period

Flue Gas Desulfurization at 90% SO_x Removal

Natural Gas Reburn/Dry Sorbent Injection at 60% NO_x and 50% SO_x Control

15% Gas of Total Boiler Fuel

Gas Fuel Price Premiums of $1 and $2 per Million BTU Compared to Coal

EPRI Cost Guidelines

1986 Dollars

TABLE 3. COMPARISON OF COSTS OF SO_x AND SO_x/NO_x RETROFIT CONTROL TECHNOLOGIES FOR 500 MW WALL FIRED BOILER

	Investment Cost		Levelized Annual Cost		1000 Tons/Yr		Cost, $/Ton	
	$Million	$/KW	$Million/Yr	Mills/KWH	SOx	NOx	SOx	SOx/NOx
Flue Gas Desulfurization	108	216	43	16	50	0	860	860
Natural Gas Reburn/ Dry Sorbent Injection								
$2/Million BTU Premium	24	48	26	10	28	7	925	740
$1/Million BTU Premium	22	45	21	8	28	7	750	600

PILOT SCALE STUDIES ON THE APPLICATION OF REBURNING FOR NO_x CONTROL

by: J. M. McCarthy
S. L. Chen
W. R. Seeker
D. W. Pershing

Energy and Environmental Research Corporation
18 Mason, Irvine, California 92718

ABSTRACT

This paper describes a pilot scale experimental study which addressed parametric and mixing effects of the reburning process, an in-furnace NO_x reduction technology, and provides scaling information and design and operation guidelines for application of reburning under a wide variety of conditions for coal- and oil-fired boilers.

The results demonstrate the potential of reburning for NO_x reduction, and indicate that important parameters include primary zone NO_x level and primary zone burnout, reburning zone time, temperature, and stoichiometry, and reburning coal transport medium. Rapid dispersion of the reburning fuel is desirable for primary NO_x incineration but can lead to an overall decrease in efficiency if the reburning fuel contains fuel nitrogen and is carried by an oxygen-rich medium. Recirculated flue gas is the optimal reburning coal transport medium, but efficient NO_x reduction with air transport can be achieved if higher reburning fuel ratios and optimal reburning mixing rates are employed. Natural gas is more effective than either coal or heavy fuel oil for reburning, especially at low primary NO_x concentrations. Reburning with coal or natural gas has little adverse effect on burnout performance. Comparison of pilot scale results and bench scale data shows that parametric effects are independent of scale and that a 50 percent reduction in emissions is achieved with 20 percent coal reburning at normal primary NO_x levels.

This paper has been reviewed in accordance with the U.S. Environmental Protection Agency's peer and administrative review policies and approved for presentation and publication.

INTRODUCTION

Reburning is a combustion modification technology which removes NO_x from combustion products by using fuel as a reducing agent. This technology, based on the principle of Myerson[1] that CH fragments can react with NO, is alternately referred to as "in-furnace NO_x reduction" or "staged fuel injection" and has been appreciated for over a decade. A flue gas NO_x incinerator using natural gas was developed and patented by the John Zinc Company[2]. The term "reburning" was coined by Wendt and co-workers at Shell Development[3] who reduced NO produced in a laboratory scale flat flame by adding methane or ammonia to the combustion products. This research concept, originally formulated in the United States, has recently been developed for application to boilers by Mitsubishi Heavy Industries Ltd. and Ishikawajima-Harima Heavy Industries Ltd. of Japan[4,5]. The MACT (Mitsubishi Advanced Combustion Technology) in-furnace NO_x removal process first applied the concept of reburning to a full size boiler. It was claimed that NO_x emissions could be reduced by at least 50 percent regardless of the reburning fuel used and the initial NO_x levels. These findings renewed the interest in the United States. EER, under contracts with Environmental Protection Agency (EPA) and Gas Research Institute (GRI), has conducted extensive bench and pilot scale testing to characterize the fundamental processes and develop a scaling methodology appropriate for use in U.S. boilers burning indigenous fuels[6-11]. Other American studies have been directed toward coal reburning[12], toward gas reburning in refinery process heaters and cement kilns[13], and toward reburning in package boilers[14,15].

The overall reburning process can be divided conceptually into three zones as illustrated in Figure 1.

- Primary Zone: This main heat release normally accounts for approximately 80 percent of the total heat input to the system and is operated under fuel lean conditions. The level of NO_x exiting this zone is defined to be the input to the reburning process. In addition, if sufficient residence time is not provided, unburned fuel fragments may leave this zone and enter the reburning zone.

- Reburning Zone: The reburning fuel is injected downstream of the primary zone to create a fuel rich, NO_x reduction zone. Reactive nitrogen enters this zone from two sources: the primary NO_x created in the main heat release zone and the fuel nitrogen in the reburning fuel. These reactive nitrogen species react with the hydrocarbon fragments formed during the potential oxidation of the reburning fuel, primarily CH species, to produce intermediate species such as HCN and NH_3. Additionally, some nitrogen is converted to N_2 and some is retained as NO. If the reburning fuel is a solid such as coal, nitrogen may also leave this zone as char nitrogen.

- Burnout Zone: In this final zone, air is added to produce overall lean conditions and to oxidize all remaining fuel fragments. The total fixed nitrogen species (TFN = NH_3 + HCN + NO + char nitrogen) will be either oxidized to NO_x or reduced to molecular nitrogen.

This paper summarizes the results of pilot scale studies which were undertaken to quantify the impact of fuel and process parameters on reburning effectiveness and provide the scaling information required for commercial application of the process under highly varied industrial conditions. Tests were conducted in a 3.0 MW refractory-lined furnace. These studies were supported by previous testing in a

25 kW bench scale facility and with finite rate kinetic modeling. The work at both scales focused on the importance and the fate of the reactive nitrogen species within the reburning zone. The experimental conditions were designed to directly simulate the 400-700 ms residence time available in a practical boiler between the burner zone and superheater tubes. Boiler heat transfer calculations suggest that the reburning fuel and the burnout air must be injected to furnace temperature zones of 1400 ± 50°C and 1300 ± 50°C, respectively, to ensure complete burnout prior to the superheater.

EXPERIMENTAL SYSTEMS

FURNACE SYSTEMS

The pilot scale studies were conducted in the 10 x 10^6 MBtu/hr (3 MW) reburning tower shown in Figure 2. The down-fired furnace was refractory-lined and water-jacketed with inside dimensions of 1.2 x 1.2 x 8.0 m. The four main burners each consisted of three concentric pipes: the inner pipe for axial injection of primary coal or fuel oil; the inner annulus for radial injection of primary natural gas; and the outer annulus, equipped with swirl vanes, for the preheated main combustion air. The furnace contained seven identical rows of ports for injection of reburning fuel and burnout air. Either recirculated flue gas or air was available for reburning coal transport. The reburning fuel and burnout air injectors were designed to maintain jet mixing similarity between the pilot-scale furnace and a full-scale boiler[16] based on empirical correlations for entrainment rate[17] and penetration[18].

The furnace had the ability to fire natural gas, coal, or oil as primary or reburning fuels, with up to 30 percent of the total load fired in the reburning zone. The temperature profile of the facility was manipulated by placement of cooling panels against the furnace walls. Further details on the design of the reburning tower and support facilities can be found elsewhere[9].

Bench-scale tests were performed on the controlled temperature tower (CTT), shown in Figure 2. The refractory-lined, 25 kW furnace was 20.3 cm in diameter and 2.5 m long. The temperature profile was adjustable via backfired heating sections within the refractory walls. The primary fuels were fired at 17.6 kW, with a premixed burner employed for gaseous and solid fuels, and a diffusion burner for liquid fuels. The reburning fuel and burnout air were injected radially. Complete descriptions of the facility and fuels employed are available elsewhere[7].

FUELS

The fuels used in the pilot scale furnace included natural gas (90 percent CH_4, 6 percent C_2H_6, and 1 percent C_3H_8 by volume), a No. 6 fuel oil (0.5 percent nitrogen), and a high volatile bituminous coal from Utah (1.3 percent nitrogen, daf). Further fuel analyses are available in the literature[9].

ANALYTICAL METHODS

Flue gas samples were withdrawn from the furnace stack with a stainless steel, water-jacketed probe and analyzed using standard continuous instrumentation (chemiluminescent NO_x, paramagnetic O_2, and NDIR CO and CO_2). Gas temperatures in the furnace were measured with a suction pyrometer.

OPERATING CONDITIONS

The baseline operating conditions for the reburning study were based on results obtained previously at EER[8] and were used for a majority of the tests performed. The total load for the pilot-scale facility was 3 MW (10×10^6 Btu/hr) with 20 percent of the load introduced as reburning fuel. The reburning fuel was injected 3.2 m from the burner face, with the burnout air injected at 4.9 m (levels four and six, respectively). Four wall-fired jets were generally used for reburning fuel and burnout air injection, with an overall stoichiometry of 1.2. The initiation of reburning tests was preceded by characterization of the furnace thermal history and uncontrolled emissions.

Uncontrolled NO_x emissions for coal- and oil-fired systems increased with excess air, with emissions of 585 and 480 ppm (dry, 0 percent O_2) at 20 percent excess air for coal and oil, respectively. The temperature profile for each system was similar to those commonly found in U.S. utility boilers(9), with the reburning fuel injected at 1360°C (2480°F).

PARAMETRIC EFFECTS

Initial tests involved the investigation of the effects of process parameters on the reburning process. Pilot-scale results were compared with those from a previous bench-scale study[7]. Results at both scales indicated that significant parameters included primary NO_x level and primary zone burnout, reburning zone residence time, temperature, and stoichiometry (SR_2), reburning coal transport medium, and reburning jet stoichiometry (SR_r).

PRIMARY NO_x

Bench-scale tests conducted with a wide variety of primary fuels (including several coals and oils, propane, and a coal/water slurry) indicated that reburning efficiency is independent of the primary fuel type as long as the primary zone residence time is sufficient[7]. Pilot scale tests conducted with coal, oil, and ammonia-doped natural gas indicate that at primary NO_x levels in excess of 600 ppm (dry, 0 percent O_2), exhaust NO_x emissions are reduced approximately 50 percent, regardless of the type of reburning fuel. At lower levels of primary NO_x when the reburning fuel contains nitrogen, reburning efficiency decreases with decreasing primary NO_x levels. However, with nitrogen-free natural gas as reburning fuel, reduction efficiency remains constant even at primary NO_x levels as low as 200 ppm.

REBURNING ZONE LOCATION

The location of the reburning zone establishes the primary zone burnout and the reburning zone temperature and residence time. All three parameters affect reburning efficiency.

To investigate the effect of primary zone burnout, two different test sequences were completed, both with Utah coal reburning. In the first test, with Utah coal as the primary fuel, the reburning injection location was moved closer to the main burner face with the burnout air location held constant. Primary zone burnout was thus reduced from about 90 to 80 percent. NO_x emissions were unchanged despite the fact that the fuel-rich residence time was doubled for the low burnout case. In the second test, the reburning zone location was held constant, and the primary fuel was changed from coal to gas. In this case the gas gave essentially complete burnout in the primary zone and substantially lower NO_x emission resulted. Both tests indicate the necessity of thorough primary zone burnout to avoid the carryover of excess oxygen into the reburning zone.

Residence time effects were studied by moving the location of the burnout air to increase the reburning residence time from 0.6 to 1.0 sec. A 50 percent relative reduction in NO_x emissions resulted. The enhanced reduction can be attributed to the increased time available for the total fixed nitrogen (TFN) species to decay in the reducing environment.

Thermal effects in the reburning zone were investigated by increasing the temperature at the reburning fuel injection location from approximately 1400 to 1500°C. A notable decrease in exhaust NO_x, attributable to increased decay rates of the TFN, was witnessed.

STOICHIOMETRIES

For application of reburning to a coal-fired boiler, the obvious choice is to use the same coal as the reburning fuel. Reburning with coal requires the use of a transport medium to carry the coal, and the impacts of the transport medium are of primary importance in commercial application. Bench-scale results have shown that the optimum SR_2 is 0.9, and that when reburning with coal, an inert transport medium ($SR_r = 0$) is desirable[7]. Studies were conducted on the reburning tower with air and flue gas recirculation (FGR) used for coal transport. Equivalent volumes (8.5 m^3/min) of flue gas or air were injected through a constant injection configuration to negate reburning zone mixing effects. The major impact variable was the transport line stoichiometry, SR_r, which is the ratio of oxygen available in the transport medium to that required for complete reburning fuel combustion. The results of the tests are shown in Figure 3.

The NO_x emissions rose substantially as the transport line became more fuel lean. Although a small change in SR_2 accompanied the change in SR_r, the increase in emissions with air transport was attributed to the increase in oxygen in the transport medium. An increase in emissions is characteristic of systems which utilize premixed burners. With high levels of oxygen available, the oxidation of reburning fuel nitrogen and hydrocarbon radicals proceeds more rapidly. This hinders the destruction of primary NO_x and increases the conversion of reburning coal nitrogen.

With air transport increasing the reburning fuel ratio to 30 percent and decreasing the primary zone stoichiometry (SR_1) resulted in substantially lower values of SR_r and SR_2, and the deviation in NO_x emission between air and FGR transport diminished. The results demonstrate the influence that the coal transport medium has on reburning efficiency and imply that this influence decreases as SR_r and SR_2 grow more fuel rich.

MIXING EFFECTS

Tests were conducted in the reburning tower to determine the effect of reburning jet and burnout air jet mixing on reburning effectiveness. Jet configurations included one large jet, four wall-fired jets, eight opposed jets, and four staggered jets (two on opposed walls). Consistent with bench scale results, pilot scale tests indicated that reburning efficiency was insensitive to burnout air mixing. Reburning jet mixing does have an impact.

Results obtained with Utah coal as both the primary and reburning fuel are shown in Figure 4. These data focus on the impacts of reburning fuel injection configuration and the FGR transport flowrate. In these tests the primary zone stoichiometry was held constant at 1.1, and the reburning fuel (20 percent), transported with 8 to 20 percent FGR, was alternately injected through four 7 cm jets and one 22 cm reburning jet from the same furnace wall. NO_x emissions were plotted as a function of the jet penetration, which was calculated from an empirical correlation[17] and verified visually. The data from both one- and four-wall-fired jets exhibited a similar trend: NO_x emissions remained constant once a minimum penetration depth was reached. However, the minimum penetration required was different for the two configurations. One large jet required nearly complete penetration, while four jets, which provided better coverage of the furnace cross-section (hence, quicker dispersion of the reburning fuel) required only 70 percent penetration. Although a further increase in penetration of the four jets increased reburning zone mixing, any enhancement induced by this was countered by the detrimental effects of an increase in SR_r and SR_2.

When the reburning coal (30 percent) was transported with air, the trend of the data, as shown in Figure 5, indicated a decrease in NO_x emissions as air flowrates, and thus SR_r and SR_2, decreased. At lower flowrates, emissions leveled off; as any further benefit from lower stoichiometries was negated by inadequate mixing. Contrary to FGR results, NO_x emissions were lower with one large reburning jet. Utilization of one jet resulted in less rapid dispersion of the reburning fuel, which promoted the existence of locally fuel-rich "pockets", wherein NO_x formation from reburning coal was inhibited. As the reburning zone became more overall fuel rich, this effect was diminished. These results demonstrate that with a reburning fuel which contains nitrogen, there exists a tradeoff between high dispersion rates for enhanced primary NO_x incineration, and low reburning jet mixing rates to minimize reburning coal nitrogen oxidation.

REBURNING FUEL COMPARISON

When nitrogen is present in the reburning fuel, a portion of the nitrogen will be converted to NO_x in the burnout zone. For this reason, a reburning fuel low in nitrogen is desirable. Experiments were carried out in the reburning tower to demonstrate the enhanced reburning efficiency attainable when reburning with nitrogen-free natural gas. Tests were conducted with the main burner fired with coal and oil.

Figure 6 presents the natural gas data and compares them with results obtained with coal and oil reburning. In these experiments, the primary zone was operated at a stoichiometry of 1.0 and the reburning fuel ratio was kept at 20 percent regardless of the fuel used. In all cases the burnout air was injected with four 15 cm jets, and the overall stoichiometry was held constant at 1.2. Different methods were used for the injection of reburning fuels. These included four 7 cm injectors for coal injection with 10 percent FGR transport, two steam atomized nozzles for No. 6 oil injection, and four 0.5 cm jets for natural gas. It can be seen from Figure 6 that independent of the primary fuel used, the nitrogen-free natural gas proved to be a more effective reburning fuel than the Utah coal and the No. 6 oil which contained 1.3 percent (daf) and 0.5 percent nitrogen, respectively.

Mixing tests indicated that the natural gas should be dispersed as rapidly as possible so that the decaying hydrocarbon radicals contact primary NO_x species. Tests completed at low levels of primary NO_x (400 ppm or less) indicated that natural gas reburning must be applied to attain reduced NO_x emissions.

Since the reburning process involves the injection of a portion of the fuel downstream of the main burner, the potential for inadequate burnout of reburning fuel exists. The influence of reburning on carbon burnout is shown in Figure 7 for a coal-fired system. No significant increase in CO emissions was witnessed for any reburning fuel type or ratio. A carbon content of one percent was measured in the exhaust ash under uncontrolled conditions. With the application of natural gas reburning, the unburned carbon in the ash increased only slightly. With 20 percent coal reburning, the unburned carbon rose to roughly 2.5 percent. Coal reburning at 30 percent yielded 5 percent carbon in the ash, but FGR was used for coal transport. For boiler application, 30 percent reburning would be utilized only if air was used for coal transport, and more complete burnout would result, but with some loss of NO_x reduction efficiency.

SCALE EFFECTS

The results of matched bench- and pilot-scale experiments designed to provide directly comparable scaling data under optimized, commercially acceptable reburning conditions with the Utah coal as the reburning fuel are illustrated in Figure 8. The exhaust emissions are shown as a function of the NO_x concentration exiting the primary combustion zone. (In both cases variations in primary NO_x were achieved by doping the natural gas to the main burner. NO was the dopant at bench scale and ammonia at pilot scale.) These studies were conducted with a primary zone stoichiometry of 1.1, 20 percent reburning fuel ($SR_2 = 0.9$) transported with FGR ($SR_r = 0.26$), a 500 ms fuel-rich reburning zone and 1430°C at the inlet of the reburning zone. The bench scale tests (25 kW) were conducted with radial reburning fuel and burnout air injection; the pilot scale tests (3.0 MW) were conducted with four 7.0 cm reburning fuel jets and four 15 cm burnout air jets, all injecting from one wall. In both cases the jets were designed to produce rapid mixing.

Figure 8 demonstrates that a 100x scaleup is possible without loss in process effectiveness if the critical stoichiometry, fuel, thermal environment, and reburning fuel dispersion parameters are matched. At normal primary NO_x levels, 20 percent reburning reduced the exhaust emissions by 50 percent; however, at low primary NO levels (400 ppm or less) the percentage reduction decreased due to the impact of oxidation of reburning fuel nitrogen.

CONCLUSIONS

Results of this study on the pilot-scale reburning tower indicate that many physical and chemical parameters affect NO_x exhaust emissions. The data generated on the reburning tower agreed with bench-scale results which implies that the influence of major process parameters is independent of scale.

The following guidelines should be observed for optimal reburning results:

- Minimize excess air levels in the main burner zone,
- Maximize the fuel-rich zone residence time,
- Allow complete burnout of the primary fuel before injection of the reburning fuel,
- Inject the reburning fuel into as hot a furnace environment as possible,
- For coal-fired systems, if feasible, use FGR as the reburning coal transport medium with approximately 20 percent reburning fuel,
- With FGR as the transport medium, the reburning fuel should be injected such that jet penetration is greater than 70 percent of the furnace depth, and coverage of the furnace cross-section is thorough, and

- If air must be used for the reburning fuel transport, increase the reburning fuel ratio to 30 percent and decrease the mixing rate of the reburning jets.

In both coal- and oil-fired systems, the reburning process was shown to be an effective method for in-furnace NO_x reduction. For highest efficiency and reduction of low levels of primary NO_x, a nitrogen-free reburning fuel such as natural gas should be used. Tests with coal and gas reburning indicated that reburning had only a minimal effect on CO emissions and carbon burnout.

ACKNOWLEDGMENTS

This work was supported by the U.S. Environmental Protection Agency and the Gas Research Institute. The guidance and encouragement of the Project Managers, J. A. Mulholland and R. E. Hall (EPA) and F. R. Kurzynske and E. E. Berkau (GRI) are gratefully acknowledged. The technical input and suggestions of the EPA Technical Advisory Panel on Reburning are also sincerely appreciated.

REFERENCES

1. Myerson, A. L., et al., Sixth Symposium (International) on Combustion, The Combustion Institute, 1957, p. 154.

2. Reed, R. D., "Process for the Disposal of Nitrogen Oxide." John Zink Company, U.S. Patent 1274637, 1969.

3. Wendt, J. O. L., et al., Fourteenth Symposium (International) on Combustion, the Combustion Institute, 1973, p. 897.

4. Takahashi, Y., et al., "Development of Mitsubishi 'MACT' In-Furnace NO_x Removal Process." Presented at the U.S.-Japan NO_x Information Exchange, Tokyo, Japan, May 25-30, 1981. Published in Mitsubishi Heavy Industries, Ltd. Technical Review, Vol. 18, No. 2.

5. Miyamae, S., et al., "Evaluation of In-Furnace NO_x Reduction, "In: Proceedings: 1985 Joint Symposium on Stationary Combustion NO_x Control, Vol. 1, EPA-600/9-86-021a (NTIS PB86-225042), July 1986.

6. Chen, S. L., W. D. Clark, M. P. Heap, D. W. Pershing and W. R. Seeker, "NO_x Reduction by Reburning with Gas and Coal-Bench Scale Studies," In: Proceedings of the 1982 Joint Symposium on Stationary Combustion NO_x Control, Vol. I, EPA-600/9-85-022a (NTIS PB85-235604), July 1985.

7. Greene, S. B., S. L. Chen, D. W. Pershing, M. P. Heap, and W. R. Seeker, "Bench Scale Process Evaluation of Reburning for In-Furnace NO_x Reduction," ASME Transactions Journal of Engineering for Gas Turbines and Power, 1985.

8. Overmoe, B. J., J. M. McCarthy, S. L. Chen, W. R. Seeker, G. D. Silcox and D. W. Pershing, "Pilot Scale Evaluation of NO_x Control from Pulverized Coal Combustion by Reburning," In: Proceedings: 1985 Symposium on Stationary Combustion NO_x Control, EPA-600/9-86-021a (NTIS PB86-225042), July 1986.

9. McCarthy, J. M., B. J. Overmoe, S. L. Chen, W. R. Seeker, and D. W. Pershing, "Pilot Scale Process Evaluation of Reburning for In-Furnace NO_x Reduction," EPA-600/7-86-048 (NTIS PB87-140323), December 1986.

10. Chen, S. L., J. M. McCarthy, M. P. Heap, W. R. Seeker and D. W. Pershing, "Bench and Pilot Scale Process Evaluation of Reburning for In-Furnace NO_x Reduction," Proceedings of the Twenty-First Symposium (International) on Combustion, Munich, West Germany, August 1986.

11. McCarthy, J. M., S. L. Chen, and W. R. Seeker, "Application of Reburning for NO_x Control to Coal and Oil Fired Furnaces," Proceedings of the Seventy-Ninth Annual APCA Meeting, 1986.

12. Kelly, J. T., R. L. Pam, and S. T. Suttman, "Fuel Staging for Pulverized Coal Furnace NO_x Control," International Symposium on Conversion to Solid Fuels, American Flame Research Committee, Paper 8, Newport Beach, CA, October 1982.

13. Yang, R. J., J. K. Arand, and F. J. Garcia, "Laboratory Evaluation of In-Furnace NO_x Reduction for Industrial Combustion Applications, ASME Paper 84-JP6C-FU-12 (1984).

14. Mulholland, J. A. and R. E. Hall, "The Effect of Fuel Nitrogen in Reburning Application to a Firetube Package Boiler," In: Proceedings: 1985 Symposium on Stationary Combustion NO_x Control, EPA-600/9-86-021a (NTIS PB86-225042), July 1986.

15. Mulholland, J. A. and W. S. Lanier," Application of Reburning for NO_x Control to a Firetube Package Boiler," ASME Transactions Journal of Engineering for Gas Turbines and Power, Vol. 107, No. 3, July 1985.

16. J. M. Beer and N. A. Chigier, Combustion Aerodynamics, Halsted Press Division, John Wiley and Sons, Inc., New York, 1972.

17. F. P. Ricon and D. B. Spalding, Journal of Fluid Mech, 11, p. 21-32 (1961).

18. G. S. Shandarov, Zh. Takhn, Fig., 37, 1 (1957).

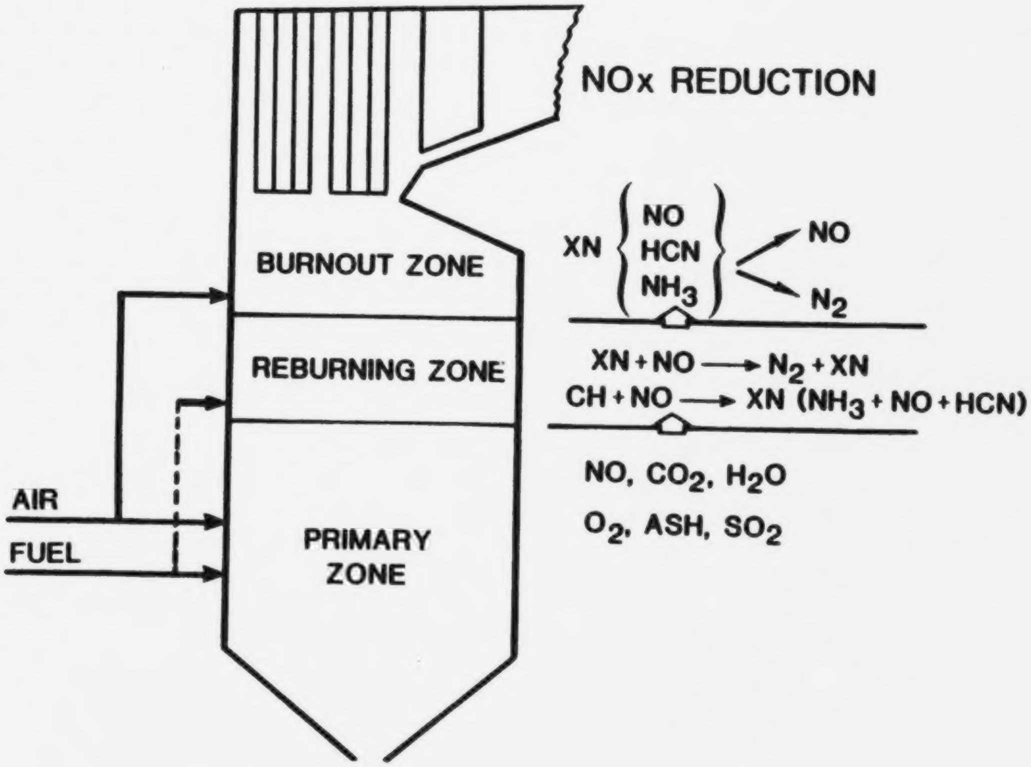
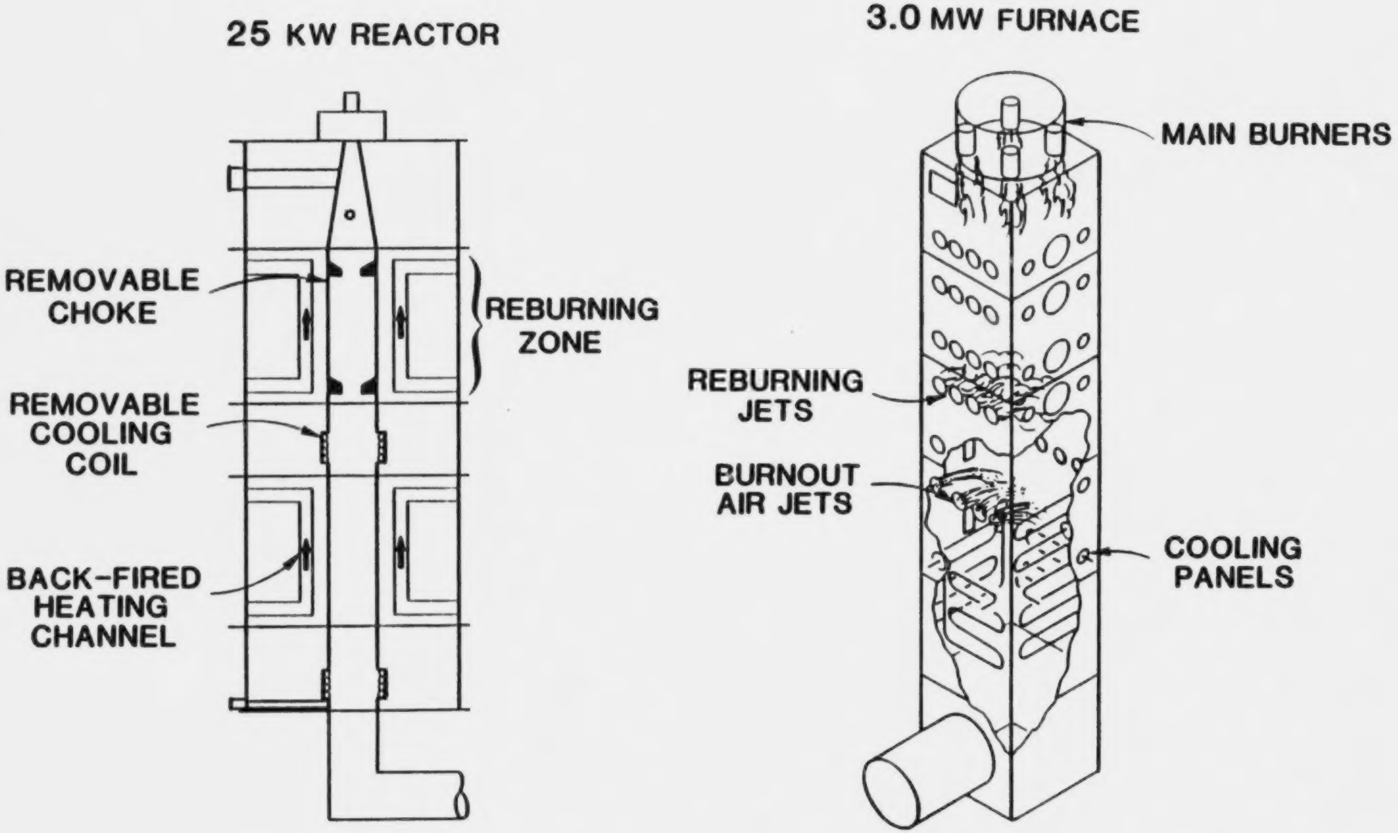

NOx REDUCTION
XN
NO
HCN
NH_3
NO
N_2
BURNOUT ZONE
REBURNING ZONE
$XN + NO \longrightarrow N_2 + XN$
$CH + NO \longrightarrow XN\ (NH_3 + NO + HCN)$
AIR
FUEL
PRIMARY ZONE
NO, CO_2, H_2O
O_2, ASH, SO_2

Figure 1. The reburning process.


25 KW REACTOR
REMOVABLE CHOKE
REBURNING ZONE
REMOVABLE COOLING COIL
BACK-FIRED HEATING CHANNEL
3.0 MW FURNACE
MAIN BURNERS
REBURNING JETS
BURNOUT AIR JETS
COOLING PANELS

- CTT
- Reburning Tower

Figure 2. Experimental Facilities.

% Reb Fuel	SR$_1$	FGR		AIR	
		SR$_r$	SR$_2$	SR$_r$	SR$_2$
10	1.0	0.65	0.95	1.56	1.04
	1.1		1.05		1.13
20	1.0	0.32	0.86	0.78	0.95
	1.1		0.94		1.05
30	1.0	0.22	0.77	0.52	0.86
	1.1		0.83		0.93

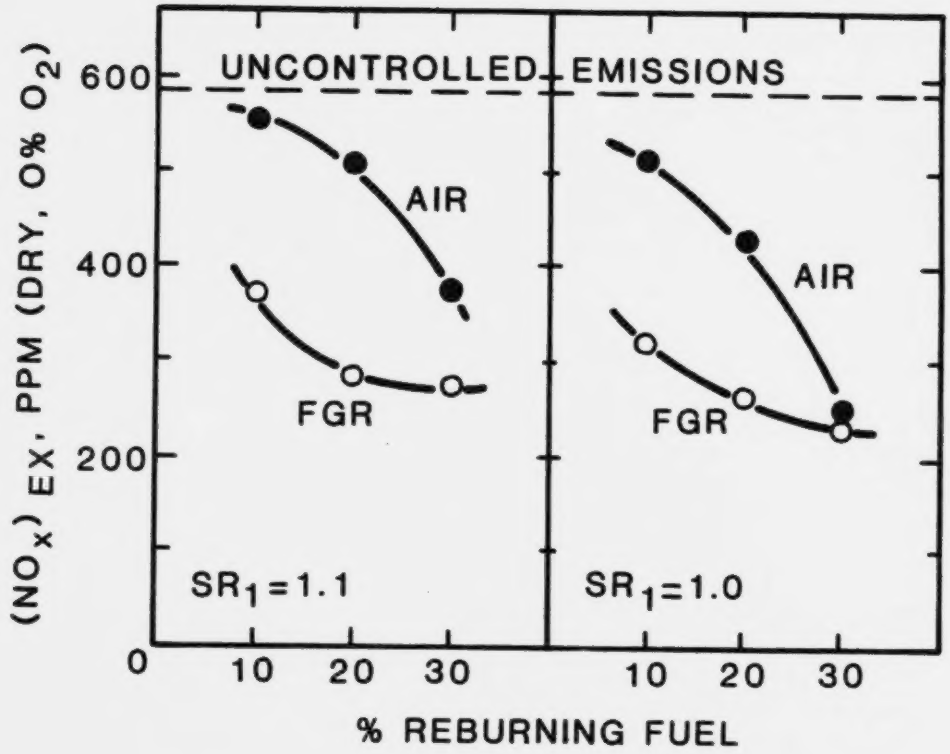


Figure 3. Stoichiometry effects on emissions.

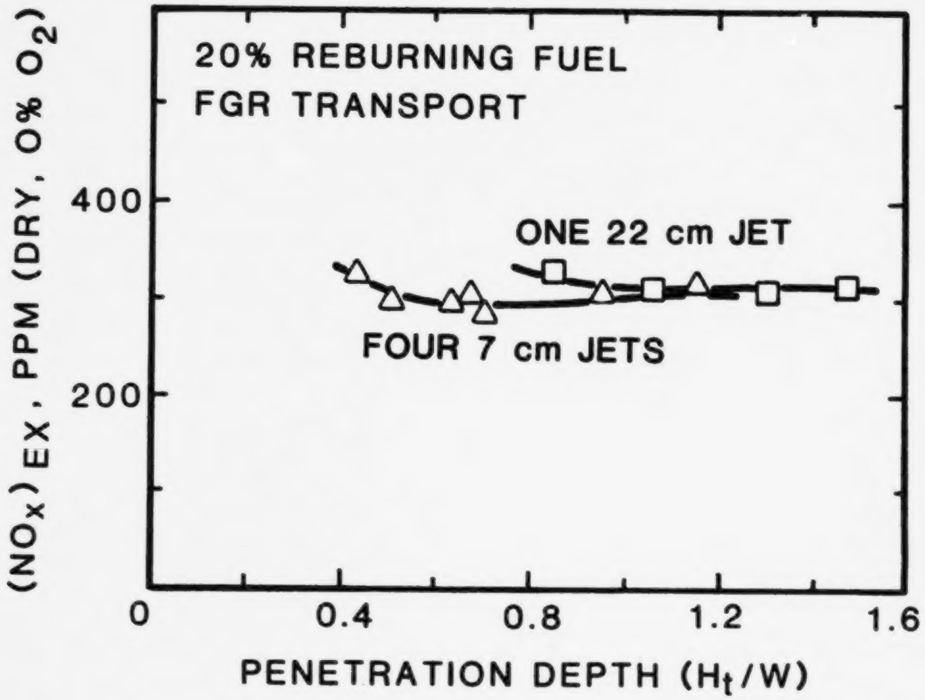


Figure 4. Mixing effects for FGR transport.

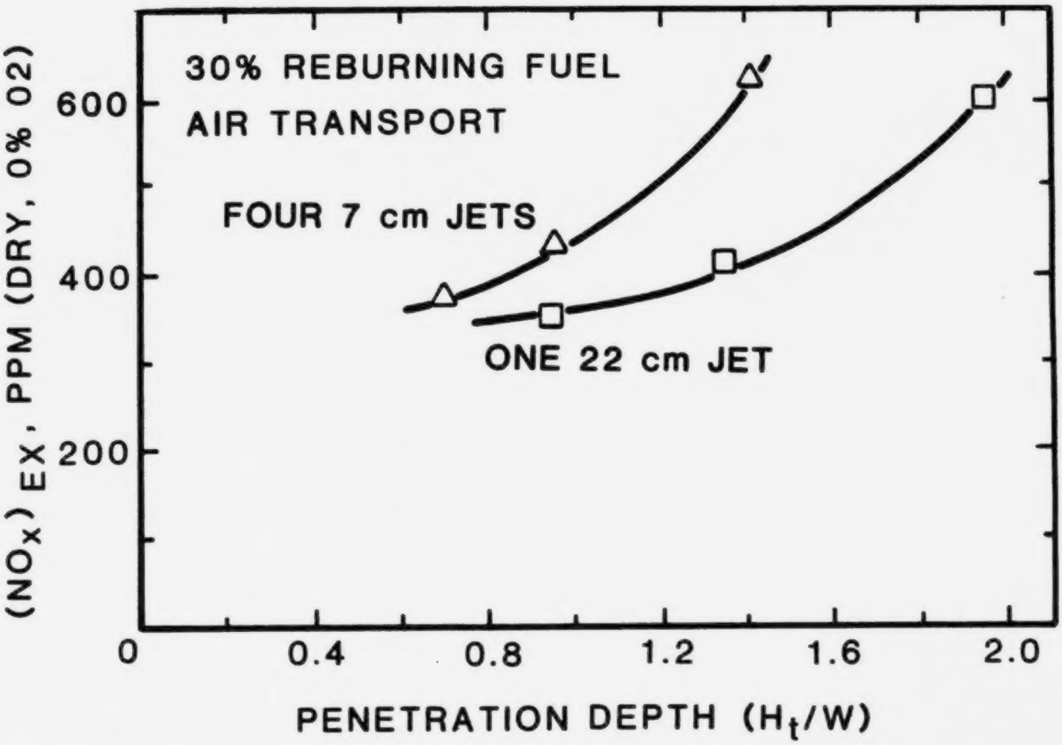


Figure 5. Mixing effects for air transport.

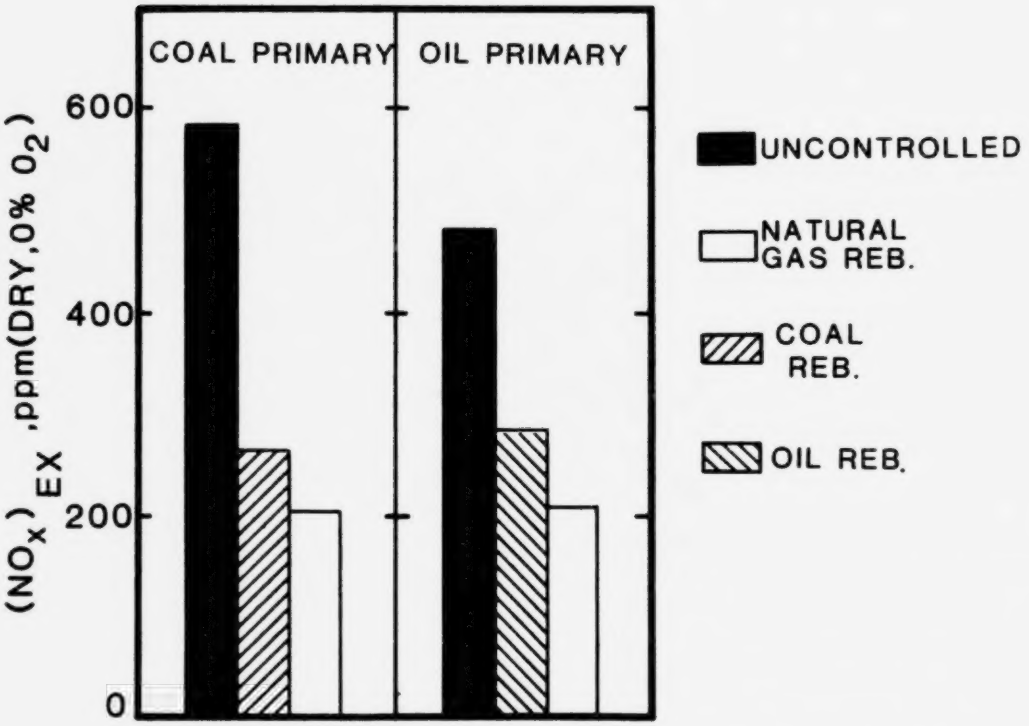


Figure 6. Advantages of natural gas reburning.

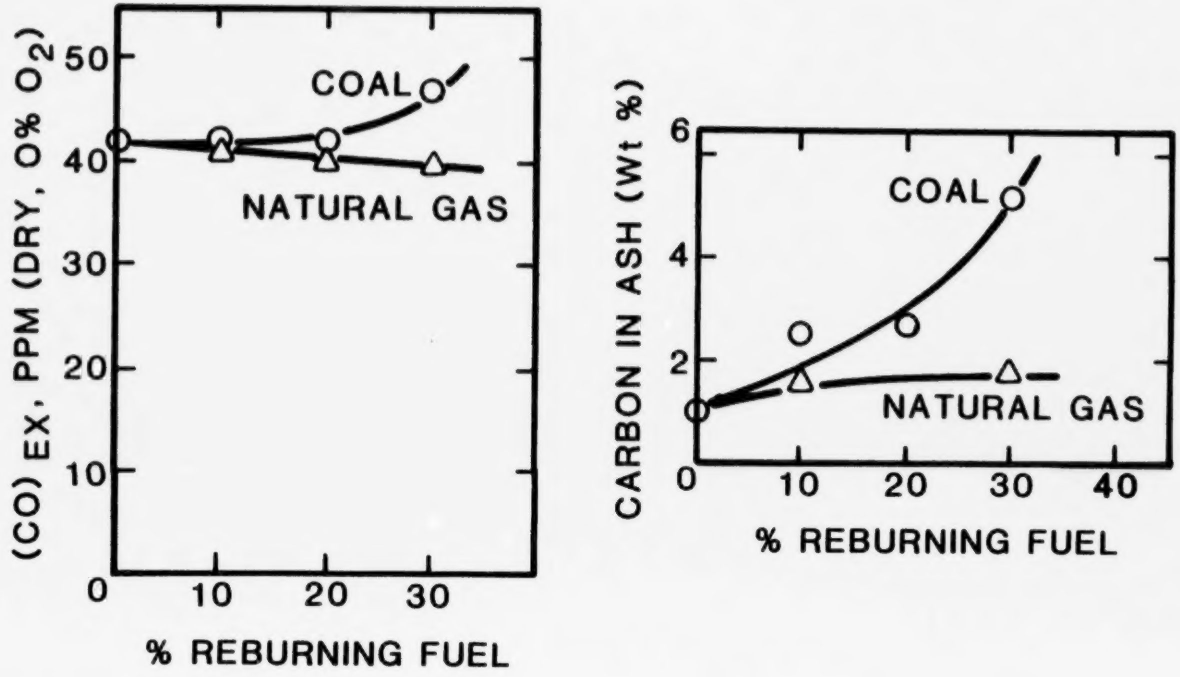


Figure 7. Reburning effect on burnout for a coal-fired system.

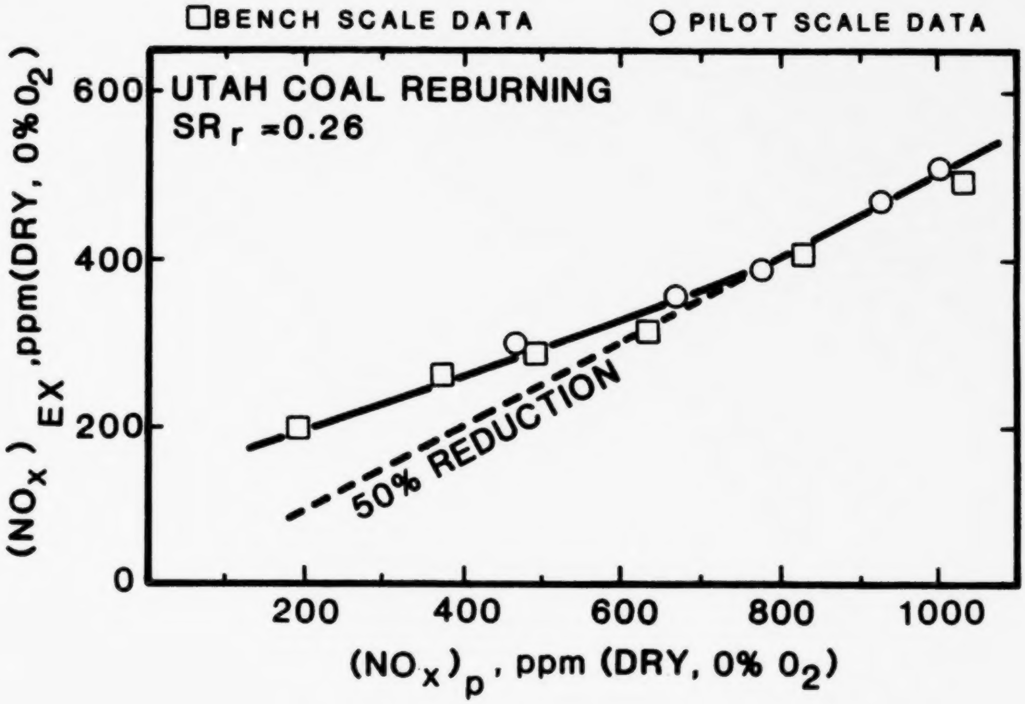


Figure 8. Comparison of bench-scale and pilot scale data.

REBURNING WITH LOW AND MEDIUM BTU GASES

by: S. J. Bortz
KVB, Inc.
18006 Skypark Boulevard
Irvine, CA 92714

G. R. Offen
Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, CA 94303

ABSTRACT

Experiments have been conducted in a 0.5 x 10^6 Btu/hr test furnace to assess the effectiveness of low and medium Btu gases as reburning fuels. These fuels, produced by coal gasification, have only trace amounts of hydrocarbons, with the combustible fraction being mainly H_2 and CO. Situations where gasification fuels may be of interest for reburning would be cyclone combustors which used crushed coal as a fuel, or boilers where there is insufficient residence time for reburning with coal. The experimental results show that the gasification fuels can reduce NO_x created in the primary flame although not as effectively as hydrocarbon fuels. Typically, the gasification fuels gave 20-30 percent reduction of primary zone NO_x compared to 60-70 percent for natural gas. If the primary zone NO_x emissions are controlled by reducing the primary zone stoichiometry to between 1.0 and 1.05, 60 percent overall NO_x reduction (compared to an uncontrolled flame) can be achieved with 15-20% use of simulated Lurgi reburning fuel. Under the same conditions, nearly 80 percent overall NO_x reduction was achieved with natural gas reburning.

INTRODUCTION

The reburning fuel has been identified as an important factor in the technical applicability and cost of using reburning to control NO_x emissions. Gaseous, liquid and solid hydrocarbon fuels have been tested in bench- and pilot-scale furnaces. When primary NO_x levels are low (200-300 ppm), natural gas has a clear advantage over coal as a reburning fuel, probably attributable to the absence of fixed nitrogen in the fuel. The same effect was observed, although to a lesser degree, when primary zone NO_x values are higher.

Gaseous reburning fuels can also alleviate burnout problems that might be encountered when using coal as a reburning fuel. Some boiler designs have a limited residence time available for obtaining both NO_x reduction and reburn fuel burnout; in these situations a gaseous reburn fuel can alleviate the burnout problems.

Reburning with a gaseous fuel has also been suggested as a possible alternative to using pulverized coal as a reburning fuel on cyclone boilers. These boilers use crushed coal as a primary fuel, and consequently would require a pulverizer to use coal directly as a reburning fuel.

Although natural gas is perhaps the most likely choice for a gaseous reburning fuel, it may not be desirable in some situations. Natural gas is not available at many utility sites, and the cost of natural gas is high relative to coal. An alternative gaseous reburning fuel to natural gas that has been suggested is the raw producer gas obtained from coal gasification. Shown below are typical gas compositions from two commercial gasifiers, one an air-blown system that produces a low Btu gas (LBG), and the other an oxygen-blown system yielding a medium Btu gas (MBG). These gases contain only trace amounts of hydrocarbons, with the combustible fraction mainly H_2 and CO.

	CH_4	CO	H_2	CO_2	N_2
Lurgi (LBG)	3.0	16.0	25.0	14.0	42.0
Koppers Totzek (MBG)	0.1	55.0	34.0	10.0	0.9

Since the major mechanism for NO_x destruction is believed to involve reaction with hydrocarbon radicals, the effectiveness of H_2 and CO as reburning gases is uncertain. In order to generate initial data about the effectiveness of typical coal gasification gases as reburning fuel, an experimental program was conducted, and the major results are reported herein.

EXPERIMENTAL FACILITY

These experiments were conducted in the KVB 0.5 x 10^6 Btu/hr combustion facility (Figure 1). The furnace is downfired, and is constructed with one-foot-long segments which can be either waterwall or refractory. Ports are located at 6" intervals along the length of the furnace, and were used as the reburning fuel or burnout air injection ports. Four ports at 90° intervals are located at each vertical position, and all four were used to inject reburning fuel or burnout air.

The first three furnace sections were refractory lined, with the remaining sections waterwall, thus giving a residence time of approximately 1.6 sec between 2400°F and 1600°F.

Hallmark coal (7.5% ash, 73.9% C, 5.2% H, 1.72% N and 3.5% S) was used as the primary fuel for all tests. The total load (primary and reburn fuel) was maintained constant at 0.5×10^6 Btu/hr during the experiments, and the overall stoichiometry was kept at 1.2. The low and medium Btu gases for the reburn fuel were simulated by mixing bottled gases to the appropriate compositions. The nominal gas compositions injected as reburn fuels are shown below.

	CO	H_2	CO_2	N_2
Lurgi LBG	16.0	25.0	14.0	45.0
Koppers Totzek MBG	55.0	34.0	10.0	1.0

Flue gas measurements were taken at the furnace exit as shown in Figure 1. The samples were drawn through a sintered filter past a gas conditioning system and into continuous gas analyzers (NO, NO_x, O_2, SO_2, CO and CO_2).

TEST PROGRAM

Reburning can yield reduced NO_x emissions through two separate mechanisms. Firstly, the NO_x emissions from the primary zone are reduced by decreasing the firing rate in the main flame. Secondly, the NO_x formed in the primary zone is partially converted to N_2 in the fuel-rich reburning zone. Often, when possible, without affecting boiler operation, the primary zone is run at a reduced stoichiometry.

Optimization of NO_x emissions when reburning requires adjustment of three major parameters: primary zone stoichiometry, reburn zone stoichiometry and percent reburn fuel. Any two of these parameters can be independent variables, with the third then becoming a dependent parameter. The manner in which these three parameters are adjusted can effect the relationship measured between the exit NO_x and any one of these three parameters.

During these experiments these three major parameters were adjusted in the following manner.

- Constant primary zone stoichiometry tests - During the test series the reburn fuel and secondary air were varied together, keeping the primary zone stoichiometry constant while the percent reburn fuel and reburn zone stoichiometry changed. In this case, the combustion air supply altered in the primary zone is also varied by the same amount to the burnout air, maintaining the overall stoichiometry constant.

- Constant reburn zone stoichiometry tests - These experiments were performed by changing the percent reburn fuel while leaving the primary zone air flow rate fixed. This changed the percent reburning fuel and primary zone stoichiometry, leaving the reburn zone stoichiometry fixed.

The effect of several other reburning parameters on exit NO_x emissions were also tested, including:

- Primary zone NOx level - Different fuels or different burner and/or furnace designs can give different NO_x levels for a given primary zone stoichiometry. The primary zone NO_x was varied by doping the secondary air with NH_3 to study, independently of other parameters, exit NO_x levels as a function of the primary NO_x.
- Reburning fuel injection temperature - During the experiments, the reburning fuel injection temperature was changed by moving the injection position, also resulting in a change in the primary zone residence time.
- Reburning zone residence time - The reburning zone residence time was varied by moving the burnout air position, also changing the burnout air injection position.

Throughout the text and figures, the following notation is used:

- LBG - Low Btu Gas
- MBG - Medium Btu Gas
- RB - Percent Reburn Fuel
- SR_1 - Primary Zone Stoichiometry
- SR_2 - Reburning Zone Stoichiometry
- SR_3 - Final Stoichiometry
- τ_1 - Primary Zone Residence Time
- τ_2 - Reburning Zone Residence Time

The test procedure used when collecting the data was as follows. The appropriate primary zone stoichiometry was established with the reburn fuel off. The NO_x was measured without the reburn fuel but with the other air and primary fuel inputs held constant. The reburn fuel was then started and the NO_x level was measured again. These two measurements gave first the primary zone NO_x and secondly the reduction of the primary zone NO_x by the reburning fuel.

Two definitions of the percentage NO_x reduction achieved are used in this paper. First the overall NO_x reduction relative to uncontrolled combustion is defined as: the NO_x measured at full load with a primary zone stoichiometry of 1.2 minus the NO_x measured at a particular reburn condition divided by the NO_x at full load with $SR_1 = 1.2$. Second, the NO_x reduction achieved in the reburn zone alone is given by the NO_x without reburn fuel minus the NO_x with reburn fuel divided by the NO_x without reburning fuel, all at fixed primary stoichiometries.

Although the NO_x data have been normalized to a constant percent O_2, the flue gas flow changes with the reburn fuel. The flue gas flow for 20% reburn fuel is 7% greater with LBG and 4% greater with MBG than with natural gas. This results in a small decrease in the ppm levels reported for the gasification fuels relative to natural gas due to dilution.

PRIMARY ZONE NO_x EMISSIONS

The NO_x emissions measured during these experiments for various loads and primary zone stoichiometries are shown in Figure 2. The primary zone NO_x is reduced for lower primary zone stoichiometries and loads (higher reburning fuel percentages). Significant NO_x reduction without affecting CO emissions were achieved by lowering the primary zone stoichiometry from a typical level of 1.2 to 1.0. Further primary zone NO_x reductions can be achieved by lowering the primary zone stoichiometry, but the CO emissions from the primary zone are increased significantly.

EFFECT OF REBURNING FUEL

The further reduction of NO_x in the reburn zone for the three different reburning fuels is shown in Figure 3. The NO_x leaving the primary zone, with a 1.0 primary zone stoichiometry, was about 500 ppm at 3.0% O_2. When reburning gas was used, 28% NO_x reduction from the 500 ppm primary zone value was measured for the medium Btu gas, 36% for the low Btu gas and 62% for natural gas. All three reburning gases gave primary flame NO_x destruction in the reburn zone, although natural gas was clearly superior.

Compared to the baseline (unstaged) NO_x emissions of 900 ppm, the percent NO_x reductions with $SR_1 = 1.0$ and 10% RB were:

- 58% with MBG
- 62% with LBG
- 78% with natural gas

The relative effectiveness of the three reburning gases were the same as shown above for all cases measured. Natural gas always gave the lowest NO_x emissions, followed by the low Btu gas, with the medium Btu gas giving the highest NO_x emissions. The difference in NO_x reductions observed for the low and medium Btu gases is generally greater than that due to the greater dilution effect with the low Btu gas.

When the reburn zone stoichiometry was held constant at 0.85 and the percent reburn fuel was changed together with the primary zone stoichiometry, the exit NO_x emissions varied as shown in Figure 4. With the natural gas reburning fuel the lowest NO_x emissions were achieved with a primary zone stoichiometry of 1.05 and 20% reburn fuel. However, the simulated gasification reburning fuels gave the lowest NO_x emissions for a primary zone stoichiometry of 0.95 and 10% reburning fuel. The difference between the exit NO_x when using natural gas and gasification reburning fuels can be attributed to their relative effectiveness in destroying NO_x created in the primary zone. Because the synthetic gases are not as effective as natural gas in reducing primary zone NO_x, the lowest exit NO_x emissions are obtained when the primary zone is operated at low stoichiometry.

If the reburn fuel percentage is changed keeping the primary zone stoichiometry constant, the NO_x emissions decrease until $SR_2 = 0.9$ (Figure 5). In general, CO emissions were increased when reburning fuel was injected. For a given reburn condition, the three reburning fuels used gave similar exit CO emissions.

EFFECT OF PRIMARY ZONE NO_x CONCENTRATIONS

In order to determine independently the effect of the primary NO_x concentration on exit NO_x emissions, the secondary air stream was doped with NH_3 to increase the primary zone NO_x emissions while maintaining the same primary zone combustion stoichiometry. These tests were conducted with a primary zone stoichiometry of 1.1, which gave a primary zone NO_x level of 750 ppm without NH_3 and 1100 ppm with NH_3. Experiments were conducted with 10% and 20% reburning fuel at both primary zone NO_x levels.

The test results (Figure 6) show that NO_x removals did increase for the natural gas reburn fuel with increased primary NO_x levels. For example, with 20% reburning fuel the undoped NO_x was decreased by 575 ppm (76%) with natural gas while the doped NO_x case was reduced by 725 ppm (65%). For the low Btu reburning fuel at the two primary zone NO_x levels, an almost constant NO_x reduction was measured, 350 ppm with the undoped flame and 375 ppm for the doped case.

Figure 7 compares the exit NO_x achieved as a function of the primary NO_x levels for the different reburning fuels (all tests were with 20% reburn fuel). The primary NO_x levels shown in Figure 7 are the measured NO_x levels entering the reburn zone, and consequently Figure 7 gives the NO_x reduction in the reburn zone alone. An estimate of the overall NO_x reduction when employing reburning requires the inclusion of a reduced primary zone stoichiometry and load on primary zone emissions. For all primary NO_x levels a significantly greater NO_x reduction was measured with natural gas than with the gasification fuels (typically 65% versus 27-36%).

EFFECT OF REBURN INJECTION TEMPERATURE AND PRIMARY ZONE RESIDENCE TIME

During the experimental program the position of the reburn fuel injection was varied, changing both the injection temperature and the primary zone residence time. The effect of the reburning fuel injection position is shown in Figure 8. With the gasifier fuels, an optimum injection temperature and/or primary zone residence time was found at 0.5 sec, corresponding to about 2400°F. The natural gas reburning fuel gave minimum NO_x emissions at 0.75 primary zone residence time, at which location the temperature was 2200°F.

REBURN ZONE RESIDENCE TIME

The effect of changing the residence time in the reburning zone (obtained by shifting the burnout air position) is shown in Figure 9. For all fuels a decrease from 0.5 to 0.25 seconds in the primary zone residence time resulted in a significant increase in the exit NO_x emissions. A 0.5 sec reburn zone residence time represents the longest residence time one can expect to be available on a real boiler.

DISCUSSION OF RESULTS

A comparison of the exit NO_x levels achieved as a function of the primary NO_x levels entering the reburn zone for coal, natural gas and the gasification fuels are shown in Figure 10. The coal reburning data as well as the natural gas data for 0.2s reburn residence time are from a similar experimental test facility (2). All the data shown are for primary zone stoichiometries of 1.05 to 1.1 and 20% reburn fuel. The coal and gasification products were run with different reburn residence times, 0.2 and 0.5s, respectively. A rough assessment of the effect of the different primary zone residence times can be acquired by comparing the natural gas data.

For high primary NO_x levels the pulverized coal gives significantly greater NO_x reductions than the low and medium Btu gases. For lower primary zone NO_x levels, less than 500 ppm, the performance of the gasified fuels was similar to coal (not taking into account the longer reburn zone residence time for the gasified fuels).

Coal or natural gas reburning fuels gave a significantly greater NO_x reduction in the reburn zone than the two gasification fuels tested to date. However, when the primary NO_x level is low, the reduced reburning efficiency of the gasifier fuels is partially compensated for by the lack of fuel N_2, allowing the low and medium Btu gases to become competitive with coal. The greater relative effectiveness of hydrocarbons, measured in these tests as compared to gasification fuels is similar to that previously measured by Kelly (3) for CO. However, more study is needed to determine the importance of the H_2:CO parameter on the reburning effectiveness. The H_2:CO ratios produced by different gasifiers can vary by approximately a factor of four.

The impact on the reburning efficiency of the trace levels (up to 10%) of hydrocarbons, such as methane and tars that exist in real coal gasification gases was not examined during these experiments and may also generate higher NO_x destruction efficiencies than "clean" simulated gases.

If the primary zone stoichiometry and/or load are adjusted to yield primary zone NO_x emission of 620 ppm or less, then the NSPS NO_x standard could be obtained with a low or medium Btu gas reburning fuel (Figure 10). However, for higher primary zone NO_x levels, the destruction of NO_x with gasification fuels is insufficient to reach the NSPS limit.

CONCLUSIONS

The results of this study have shown that gases representative of coal gasification processes can be used as a reburning fuel, although hydrocarbon fuels are more effective. Natural gas gave 55-65% reduction of primary zone NO_x emissions, while the low and medium Btu gases gave 20-30% NO_x reductions. Reburning with the gasification products could produce low exit NO_x emissions if used in conjunction with low NO_x burners, low excess air, or staged combustion in the primary zone. For example, 60% NO_x reduction (relative to uncontrolled emissions) was obtained with low Btu gas at a primary zone stoichiometry of 1.0 and 15% reburn fuel.

Trace quantities of tars and hydrocarbon gases and/or different H_2:CO ratios present in real gasification products may give higher NO_x reductions in the reburn zone than measured with the clean fuels used during these experiments.

ACKNOWLEDGMENTS

This work was sponsored by the Electric Power Research Institute. The authors would like to acknowledge the contributions of John Arand and Paul Quandt who conducted these experiments.

REFERENCES

1. Wendt, J.O.L., et al. Fourteenth Symposium (International) on Combustion, The Combustion Institute, 1973.

2. Chen, S. L., McCarthy, J. M., Heap, M. P., Seeker, W. R., Pershing, D. W. and Kurzynske, F. R. Controlling pollutant emissions from coal and oil combustors through the supplemental use of natural gas. Paper presented at 1986 Joint Symposium on Dry SO_2 and Simultaneous SO_2/NO_x Control Technologies. Raleigh, North Carolina, 1986.

3. Kelly, J. T. and Suttman, S. T. Fuel staging NO_x control. DOE/PC-50268-5, U.S. Department of Energy Report, Washington, D.C., 1984.

The work described in this paper was not funded by the U.S. Environmental Protection Agency and therefore the contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

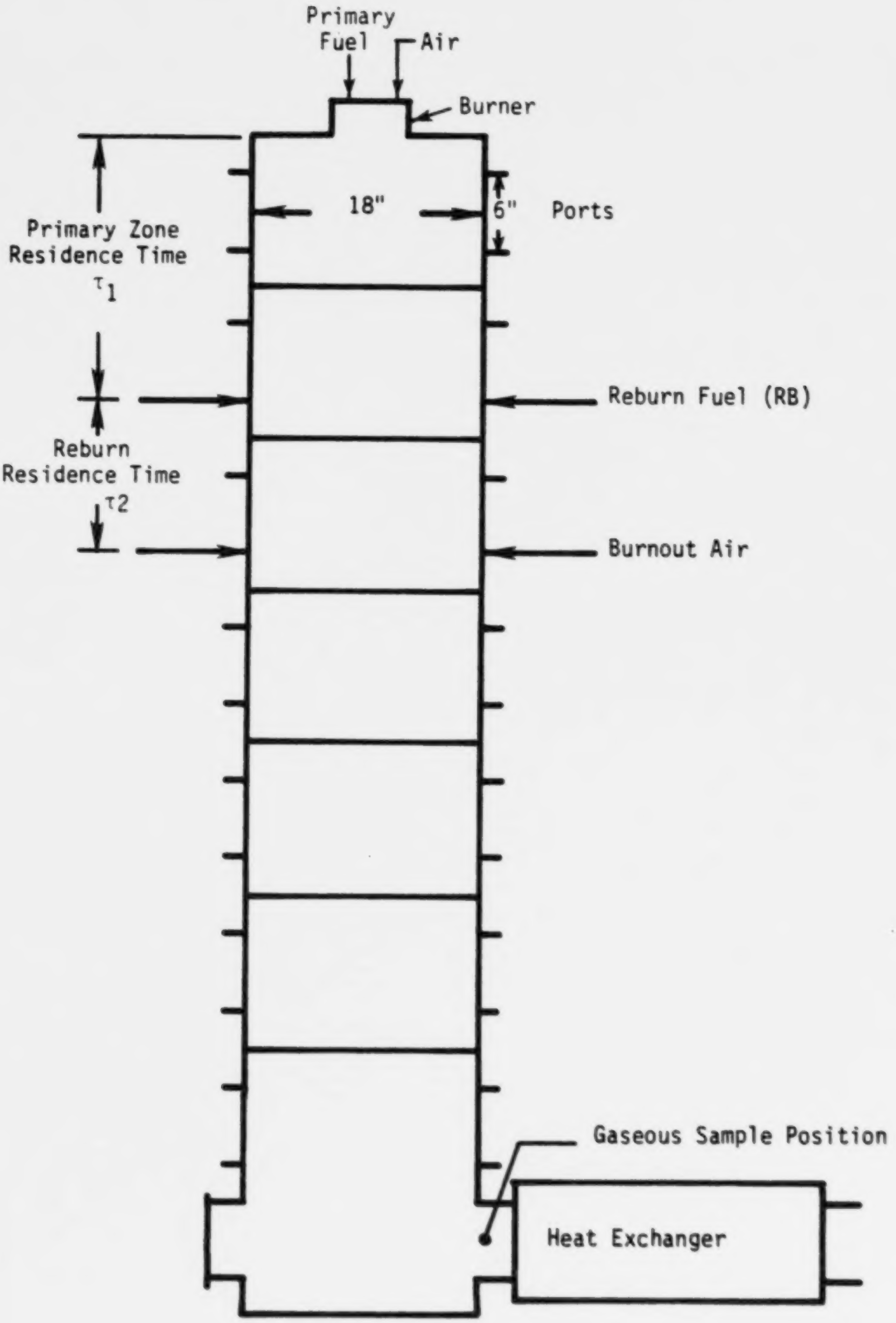

Primary Fuel
Air
Burner
18"
6"
Ports
Primary Zone Residence Time τ_1
Reburn Fuel (RB)
Reburn Residence Time τ_2
Burnout Air
Gaseous Sample Position
Heat Exchanger

Figure 1. Pilot furnace configuration for reburning.

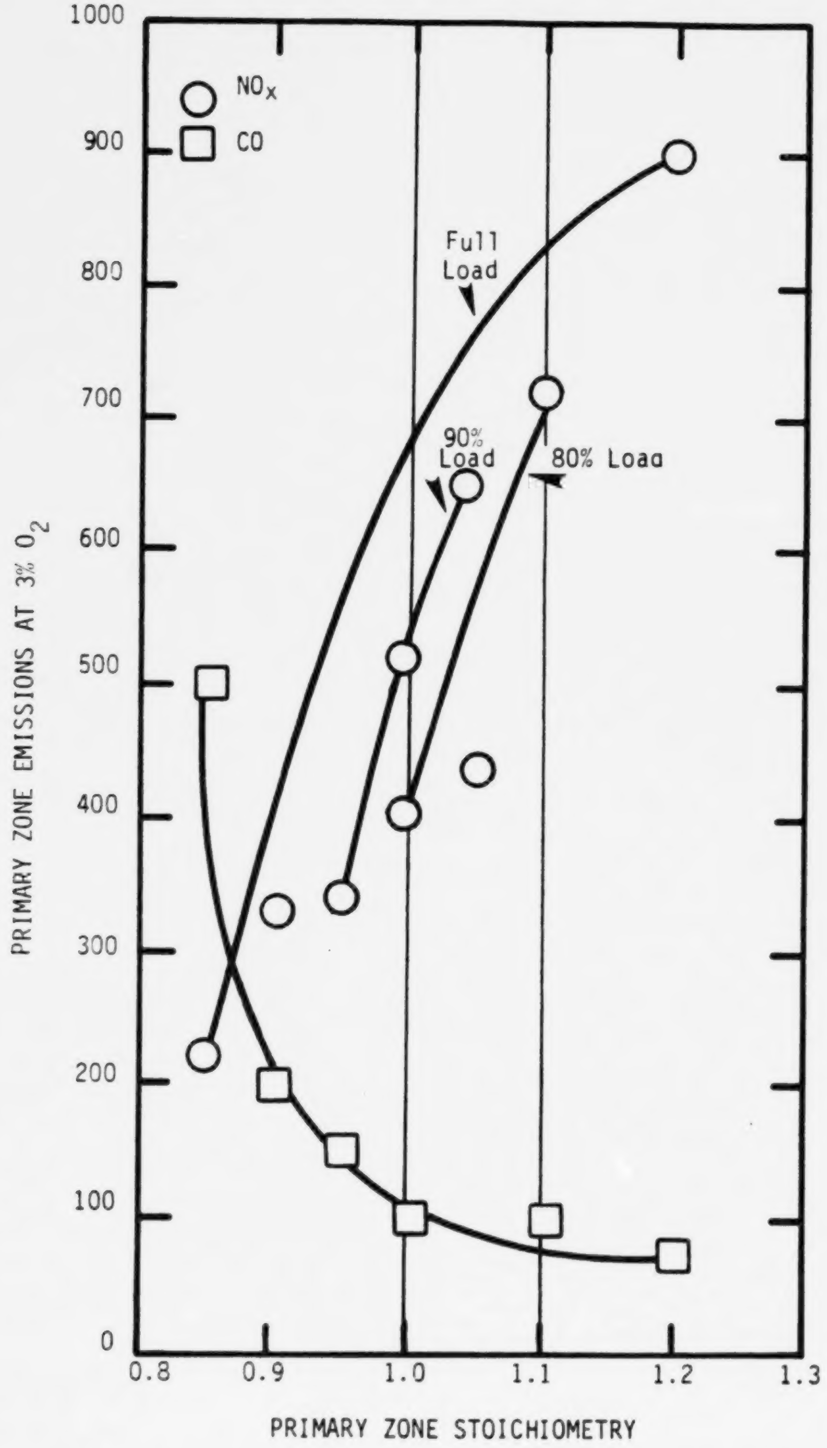


Figure 2. Effect of primary zone stoichiometry and load on the primary zone NO$_x$ and CO SR$_3$ = 1.2.

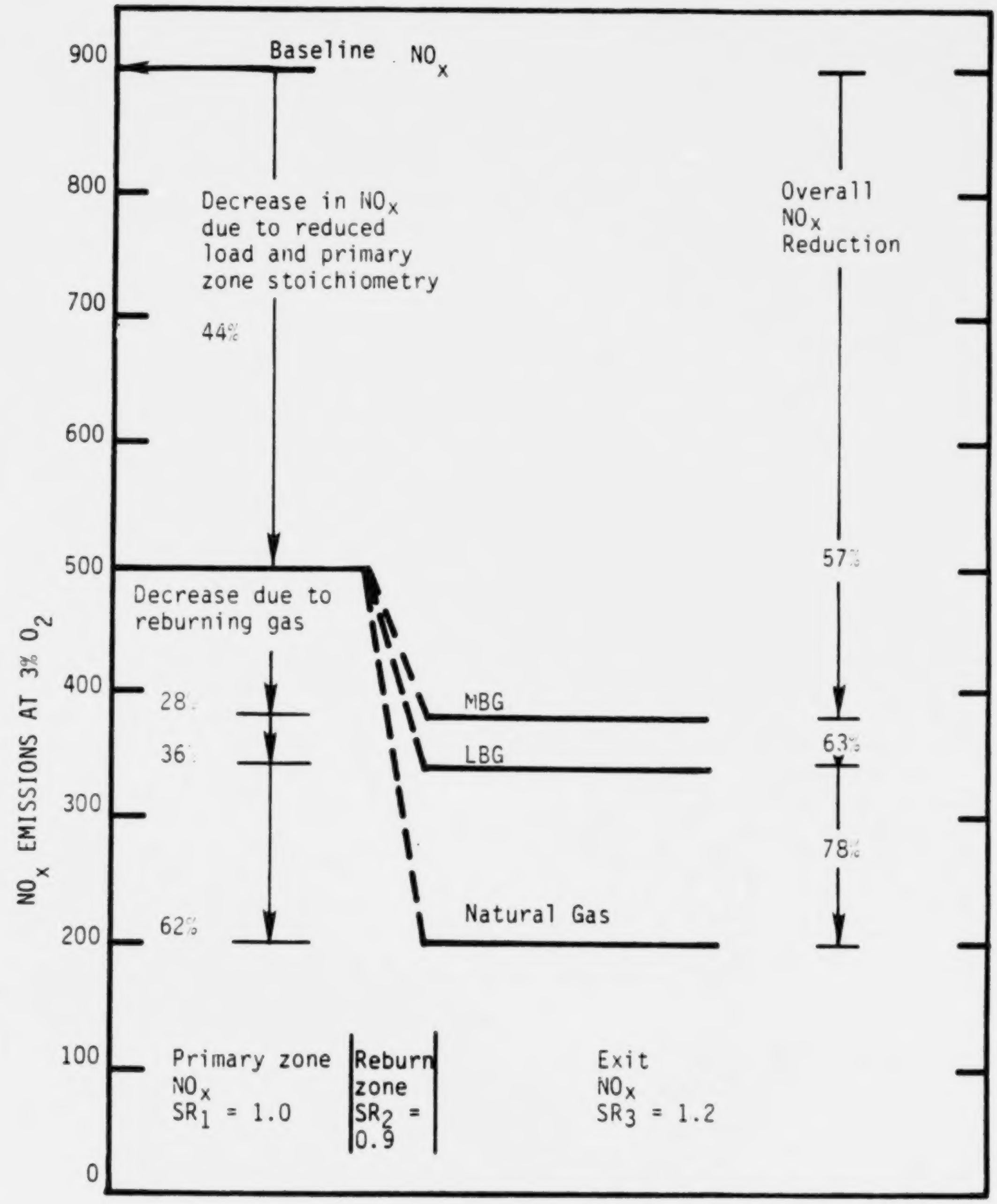


Figure 3. Effect of reburning on primary zone NO$_x$ emissions

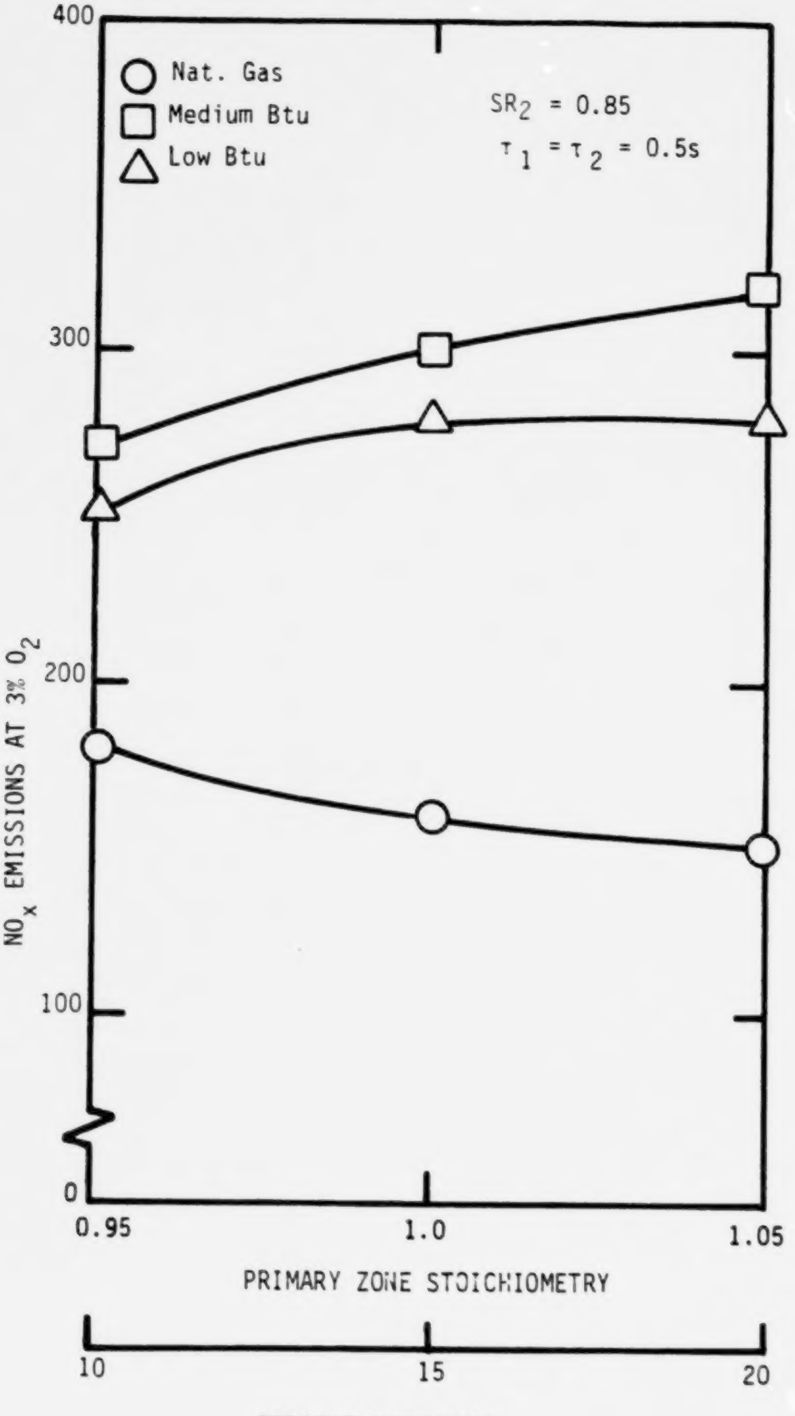


Figure 4. Effect of percent reburn fuel on exit NOx levels.

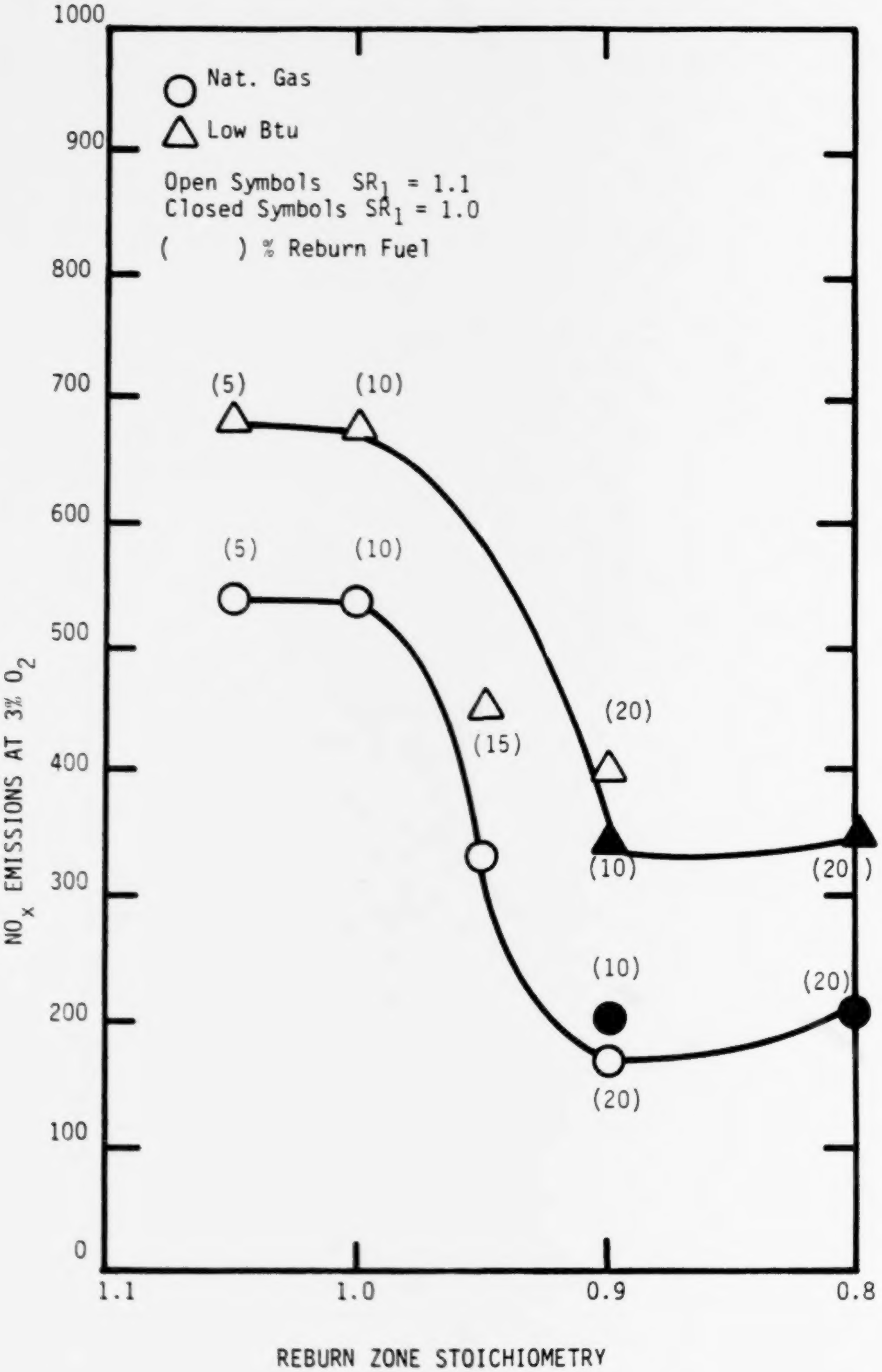


Figure 5. Effect of reburning zone stoichiometry

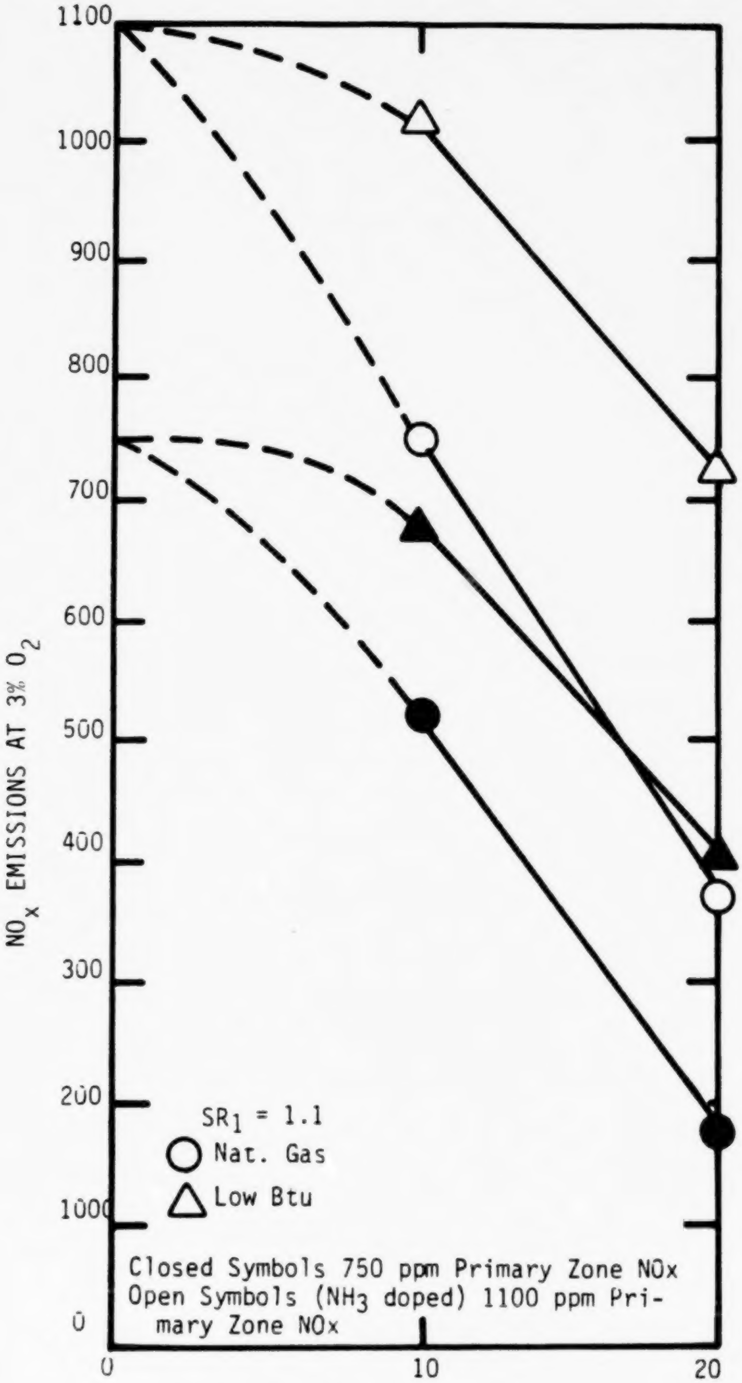


Figure 6 . Effect of percent reburning fuel for different primary NOx levels.

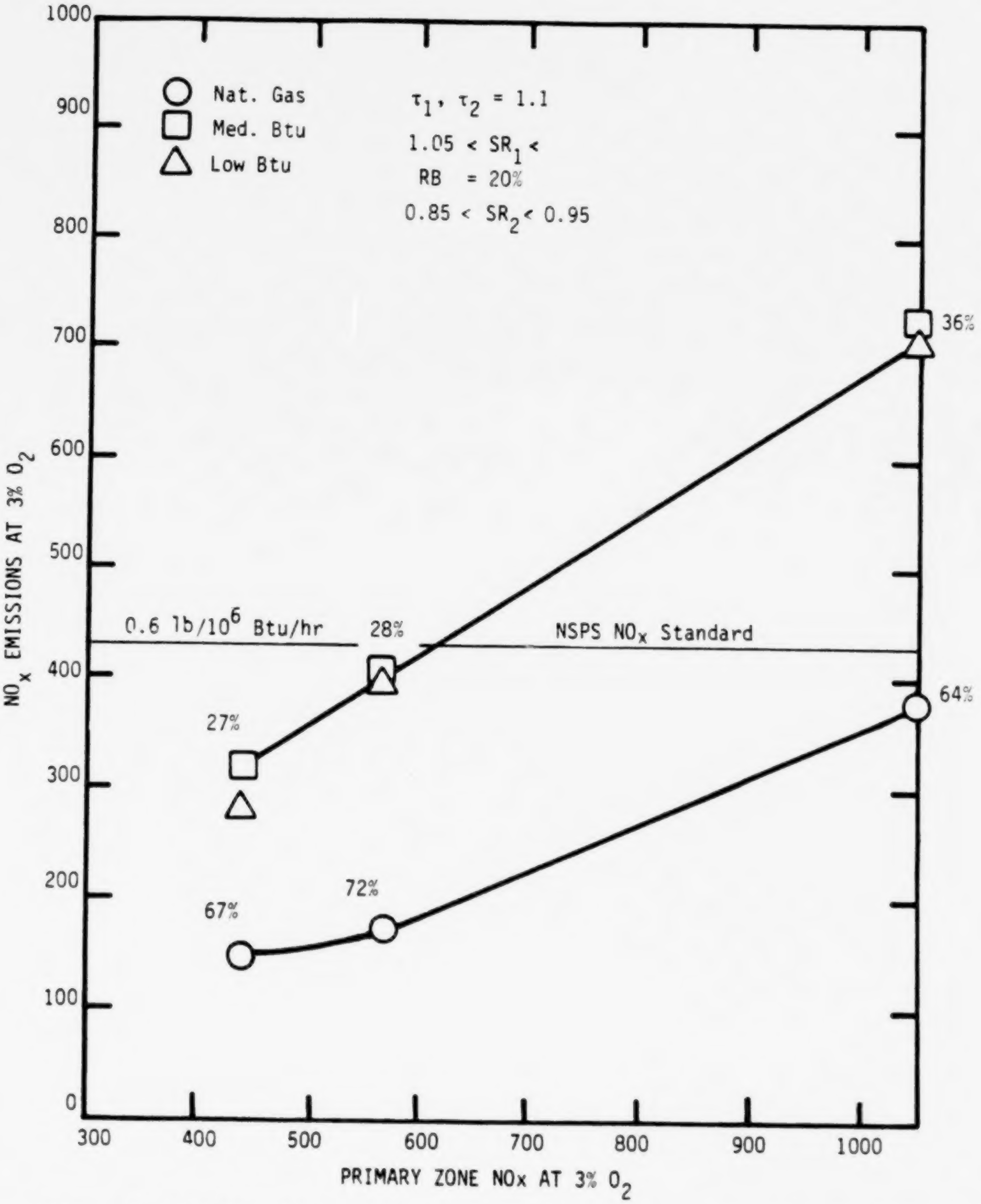


Figure 7. Relationship between the primary zone NO_x and final NO_x for fixed reburn zone conditions.

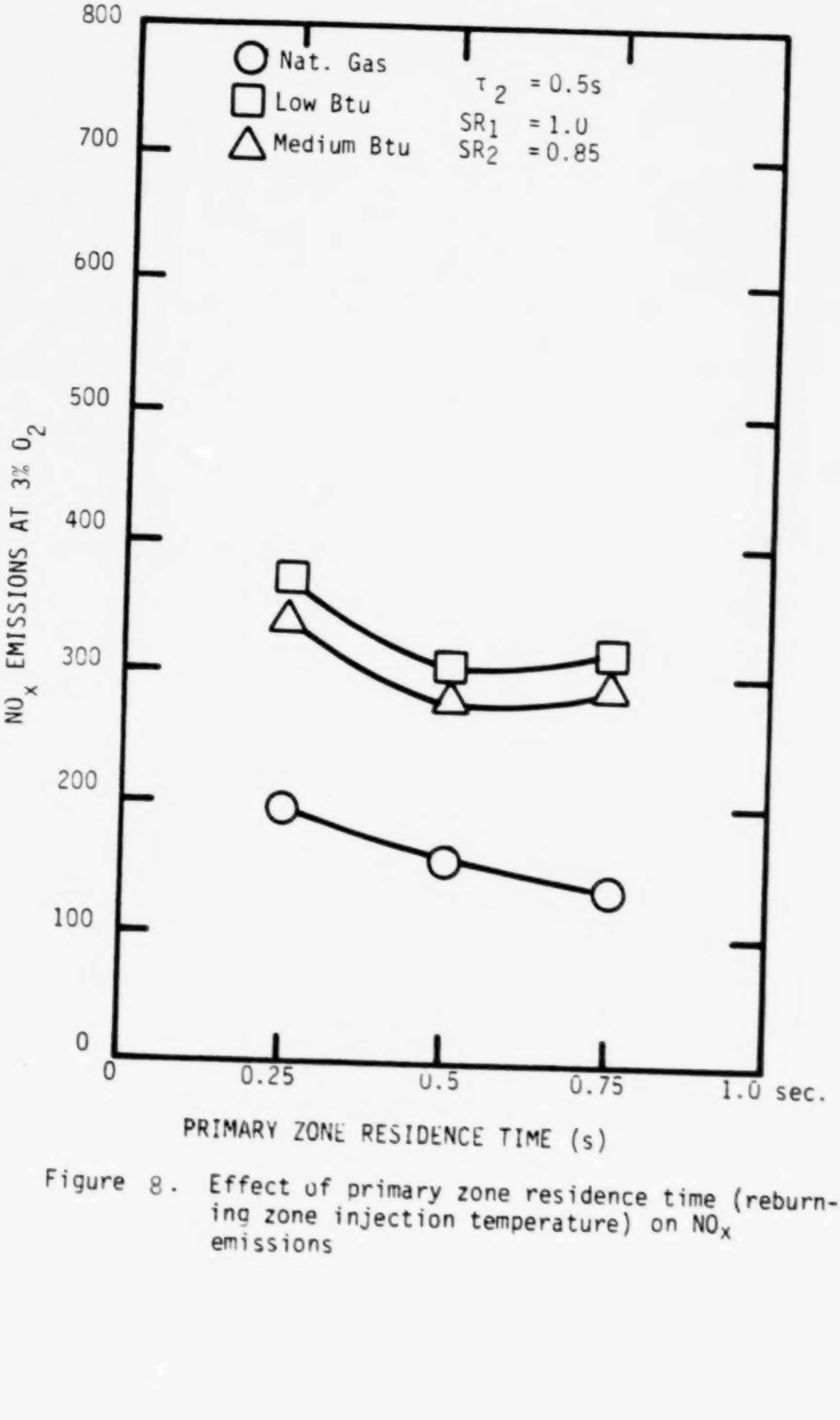


Figure 8. Effect of primary zone residence time (reburning zone injection temperature) on NO_x emissions

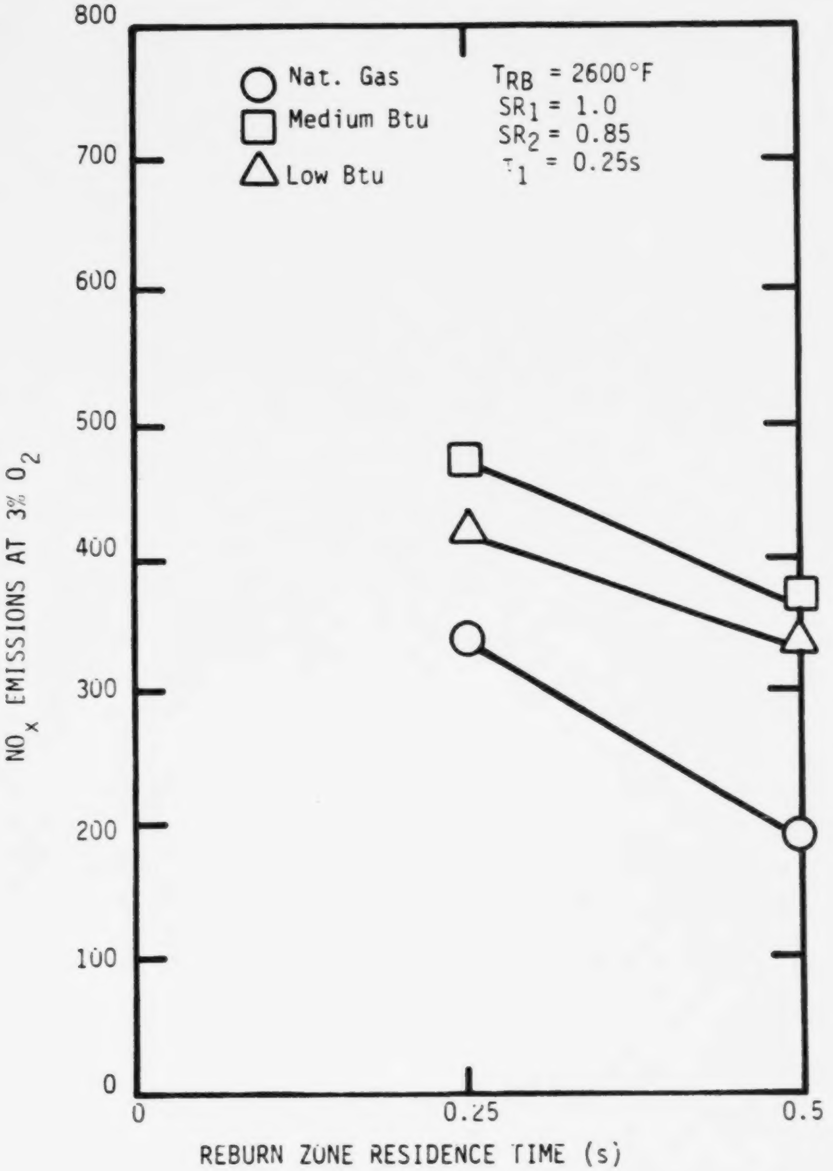


Figure 9. Effect of reburning zone residence time on NO$_x$ emissions

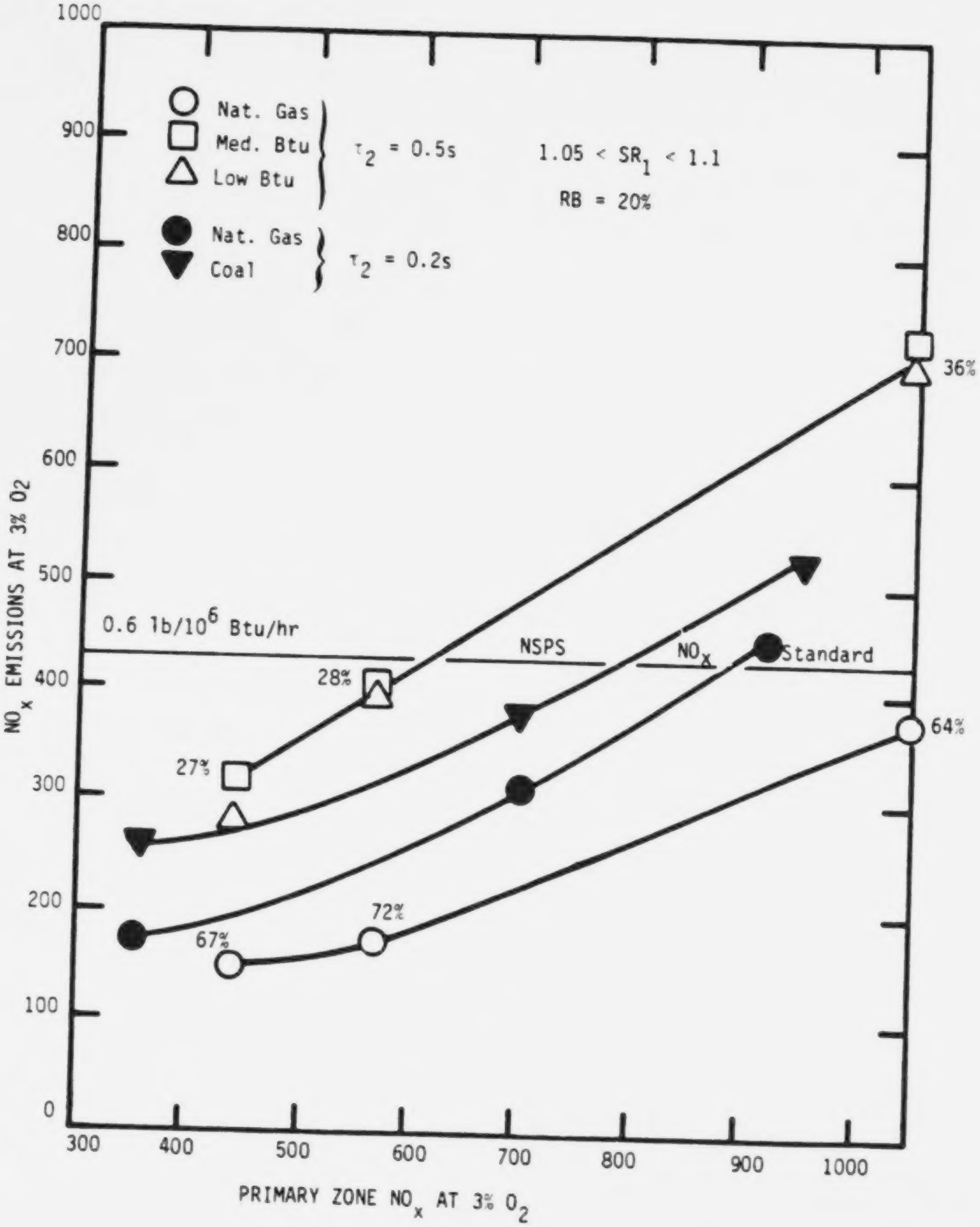


Figure 10. Comparison of NO_x reductions achieved with natural gas, low and medium Btu gas, and coal.

1987 UPDATE ON NOx EMISSIONS CONTROL TECHNOLOGIES AT COMBUSTION ENGINEERING

M.S. McCartney, A. Kokkinos, R.D. Lewis, T.D. Hellewell, M.B. Cohen
Fossil Power Systems, Combustion Engineering, Inc.
Windsor, Connecticut

ABSTRACT

As the owners and operators of fossil fuel fired steam generators plan for the 1990's, new emphasis is being placed on the control of NOx emissions. This emphasis is the result of a resurgence in the concern, both domestically and internationally, regarding the effects that NOx emissions may have on the environment.

At Combustion Engineering, work is continuously underway to support these owners and operators. As shown in previous Joint NOx Control Symposia, Combustion Engineering has a diverse array of NOx Reduction Technologies available to address a range of possible reductions dictated by future regulations. These technologies have been developed by Combustion Engineering and Mitsubishi Heavy Industries (MHI); MHI developed technologies have been licensed to Combustion Engineering.

A synopsis of each of these technologies and the applications and operating experience related to them is presented here.

INTRODUCTION

Public concern for environmental quality, potential state or federal acid precipitation legislation, and utility programs for boiler life extension all play key roles as utilities reexamine their plans with regard to NOx control technologies. Some regulatory agencies, particularly in the European Economic Community (EEC), have set extremely stringent NOx emissions control levels. In some European countries, West Germany in particular, the NOx emissions control levels are so stringent that they are forcing the use of post combustion catalytic NOx reduction systems.

In the United States, work is underway to demonstrate NOx control technologies which are retrofitable to existing steam generators. In-furnace NOx control technologies have received particular attention because of the lower capital and operating costs. This tact has been taken to offer a technological alternative to the approximately 85% of all U.S. utility boilers built before the 1971 EPA NOx control regulations.

In this paper Combustion Engineering will present an updated synopsis of the NOx control techniques that it offers. The NOx control techniques presented in this discussion are systems which Combustion Engineering has developed or has licensed to build from Mitsubishi Heavy Industries, Ltd. (MHI) of Japan. A comparison of various NOx reduction techniques for tangential coal fired utility boilers is shown in Figure 1. This paper will primarily focus upon design application and recent experience with NOx reduction techniques referred to as the PM burner, the Low NOx Concentric Firing System (LNCFS), and Selective Catalytic Reduction (SCR) system.

Each of the systems presented in Figure 1 has a maximum percent NOx reduction which, in the opinion of C-E, represents the practical technical limits for that technology. The degree of NOx control is compared to a base of 100% which would be typical of pre-New Source Performance Standard (NSPS) tangential fired units designed in the mid to late 1960's. For retrofit applications, the degree of NOx control may vary somewhat from the values presented depending upon physical and operational restraints encountered.

CONCENTRIC FIRING SYSTEM

Virtually all of the current low NOx burner systems are designed to reduce the availability of oxygen at some point in the history of the fuel within the furnace. In the early 1970's, designers of fuel burning equipment pursued the reduction of high temperature zones within the furnace in an attempt to control the THERMAL portion of total NOx - e.g., simply stated, NOx = Thermal NOx + Fuel NOx. Most of the recent fundamental research on the kinetics of fuel-bound nitrogen focus on the very early devolatilization process, an initial period of events in the combustion process during which very large quantities of fuel nitrogen are released. The potential for nitrogen conversion to NOx is high at this time. Overfire air (OFA) plays a minor role in controlling NOx formed early in the combustion process, because the 15% to 20% of the total air that goes to the OFA is a very small part of the O_2 available to the volatile matter being burned and fuel nitrogen being released. Thus, to control the all-important fuel nitrogen conversion, large quantities of air must be withheld from the fuel for the duration of the devolatilization and small char particle combustion process. By withholding a sufficient quantity of air from the combustion of volatile matter, the system is simultaneously deprived of a sufficient quantity of O_2 to oxidize nitrogen to NO. The ideal system of igniting and burning pulverized coal would be to pre-mix a minimum amount of air with the pulverized coal, promote strong ignition, and then mix the balance of the required air at a later stage of the combustion process.

C-E's traditional tangential firing system injects air towards the periphery of an imaginary circle (Figure 2). The windbox handles four distinct air zones.

1. Primary air is used to dry and transport the coal, and is injected into the furnace through the coal nozzle assembly.

2. Fuel air is that portion of the windbox air (secondary air) that is injected into the furnace annularly to the primary air.

3. Auxiliary air is the balance of the air required for combustion that was not used by the primary or fuel air or overfire air. Most of the auxiliary air is injected into the furnace through separate compartments located in between each fuel compartment.

4. Overfire air(OFA) is the remaining auxiliary air that is introduced to the furnace through OFA ports located at the top of (or above and separate from) the main windbox.

The rotating "fireball" pattern that is unique to tangential firing is formed by directing fuel and air streams tangent to an imaginary circle as illustrated in Figure 3. Only a small fraction of the total kinetic energy of the fuel and air streams is used for rotating the gas within the furnace. The rotational velocity of the air and fuel streams is referred to as swirl, and can be quantified by the use of a swirl number, which is proportional to the ratio of angular momentum to axial momentum.

LOW NOx CONCENTRIC FIRING SYSTEM

In 1980, C-E developed a firing system concept referred to as the Low NOx Concentric Firing System (LNCFS). The LNCFS proportioned the secondary air flow through the windbox so as to effect a decrease in the amount of fuel air while increasing the amount of auxiliary air. In addition, the auxiliary air was directed away from the fuel towards the furnace wall in order to reduce the entrainment of auxiliary air by the expanding primary air/coal jet (Figure 4).

Redirecting the auxiliary air away from the furnace diagonal is estimated to have increased the swirl number by a factor of two. As with OFA, LNCFS effectively withholds air from the fuel stream. In addition, LNCFS effects favorable stoichiometric conditions for low NOx emissions in the initial combustion process. Both OFA and LNCFS can be referred to as "staging" techniques. OFA is a type of "vertical staging" for controlling NOx emissions, while LNCFS can be thought of as a "horizontal staging" technique - unique to tangential firing.

As a practical matter, LNCFS affects the "early stoichiometry" for a very limited amount of time. The cross mixing patterns inherent in tangential firing are massive and separation of both streams are quickly lost as they penetrate the furnace. Thus LNCFS requires the use of "flame attachment" nozzle tips to accelerate the devolatilization process. Thus to retrofit LNCFS, all the air and fuel nozzle tips require replacement (Figure 5). No structural windbox or pressure part changes are normally required; after OFA, LNCFS is the next least costly modification available to reduce NOx. For a unit without provisions for OFA, LNCFS can be economically installed, in view of periodic replacement of fuel nozzle tips due to erosive wear.

An extensive field demonstration of the LNCFS concept was conducted at Utah Power and Light, Hunter #2, under EPA contract. Results from these tests were presented in previous symposia (Ref. 1 and 2) and in the EPA final project report (Ref. 3). More recently C-E's licensee in Great Britain, NEI International Combustion Ltd. has completed the demonstration of an LNCFS system at the Central Electric Generating Board (CEGB) Fiddlers Ferry No. 1 Power Station. This is a 500 MWe base loaded utility unit. A schematic of the unmodified and LNCFS windboxes at Fiddlers Ferry #1 is shown in Figure 6. Figure 7 presents typical NOx emission results from this unit. Figure 7 also shows a comparison of these results to the NOx emission levels achieved at UP & L Hunter #2. Emission levels for the unmodified or baseline configuration at Fiddlers Ferry #1 have been inferred based on emission tests at the 400 MWe Fiddlers Ferry #4 unit (Ref. 4).

As shown in Figure 7, the mean NOx reduction achieved with the LNCFS was approximately 35%. Boiler performance and efficiency before and after the modification were identical. Additionally, with the LNCFS the furnace atmosphere is more oxidizing than with the unmodified boiler. A more detailed discussion of the LNCFS test at Fiddlers Ferry #1 is presented later at this symposium and is contained in Ref. 4.

(OFFSET) CONCENTRIC FIRING SYSTEM (CFS)

The LNCFS described above was primarily designed as a retrofitable windbox modification for reducing NOx emissions on coal fired boilers equipped with tangential firing. It was originally anticipated that the increase in furnace turbulence due to higher swirl numbers would provide the necessary fuel and air final mixing in the furnace following the initial separation for NOx emission control between the fuel and auxiliary air streams. Actual field experience on several utility boilers revealed significantly improved furnace performance following the addition of LNCFS. In order to focus on other advantages associated with this system aside from the reduction of NOx emissions, a simplified version of the LNCFS was developed and installed in the field. This new system is called Concentric Firing System (CFS) and involves replacement of the auxiliary air in a manner described above under LNCFS. Unlike LNCFS, the CFS does not require the use of flame attachment nozzles or the redistribution of secondary air. CFS, thus, has minimal impact on NOx emissions.

Over 20 installations of CFS have demonstrated significant increase in fireball rotation and swirl. One effect of this increase in furnace turbulence is to shift a portion of the radiant heat transfer from the upper furnace to the lower furnace. As a result, there is a net increase in total furnace absorption and a corresponding decrease in furnace outlet temperature.

From the viewpoint of the boiler operation, the CFS modification yields a decrease in desuperheater spray requirements. In addition, furnace wall deposits are typically drier and less prone to fuse and produce molten slag. Based upon visual observation at operating units, ash deposition has been found to be more uniformly dispersed throughout the furnace. Finally, the characteristics of the ash deposits are drier, more friable and more receptive to removal by soot blowers. Also, although the CFS system only minimally effects NOx emissions, the beneficial effects on furnace performance seen with CFS will be applicable to LNCFS retrofits.

C-E/MHI PM BURNER

The coal fired PM burner system is part of a family of ultra low NOx burners capable of firing coal, oil, and gas. The PM system was developed by Mitsubishi Heavy Industries (MHI) and has been licensed to Combustion Engineering for application in North America. In addition to using a bulk staging combustion technique (OFA), the PM burner emits low NOx emissions by reducing the local stoichiometry (available O_2) around the coal particle early in the combustion process. The extensive laboratory work behind the PM burner has gone further to identify a relationship between NOx and the pulverized coal/air transport ratio. As seen in Figure 8, MHI tests show that typical transport air/fuel ratios (NOx value at CO) are not conducive to low NOx. In fact, air to coal ratios that are either higher or lower than typically found in modern pulverized coal units would result in lower NOx. With the benefit of this information, the PM burner is quite straightforward. Since the primary air to fuel ratio from the pulverizer cannot as a practical matter be changed, the MHI burner splits the fuel pipe and the windbox and separates the fuel in two streams (see Figure 9). In theory, neither the fuel rich (CONC) nor the air rich (WEAK) injection nozzle has a fuel nitrogen conversion ratio as high as a single nozzle with the air and fuel combined (See Figure 8). In practice, this theory has been supported by both large scale laboratory prototype testing as well as field testing in a large industrial boiler in Japan.

Under EPRI sponsorship, the coal fired PM protype was demonstrated on a variety of U.S. coals ranging from Texas lignite to eastern bituminous coals. The results of this testing are presented in Figure 10 and Figure 11 (Ref. 5, 6, and 9). Figure 12 and 13 are of particular interest because they show the sensitivity of the system to the use of gas recirculation (GM or SGR).

The results of the data clearly show that the absence of gas recirculation does not significantly detract from the PM burner performance. The use of gas recirculation can be effective in controlling NOx emissions for low reactivity fuels. However, it is not generally required for NOx control for typical U.S. coals. Therefore, gas recirculation is not normally specified for PM coal applications.

Recent operating experience with the Coal Fired PM Burner has been reported in Reference 9. USA western bituminous coals have been fired in PM burners installed in Japanese industrial and utility boilers. Field test results indicate NOx emissions of less than 150 ppm (corrected to 3% O_2) when firing these U.S. coals with PM burners.

Currently Combustion Engineering is in the process of retrofitting a PM firing system into Kansas Power and Light Co. Lawrence No. 5. The installation is being funded jointly by KP&L and several utility R&D organizations. Separate contracts have been awarded by the Electric Power Research Institute (EPRI) to both C-E and a team made up of Fossil Energy Research Corporation (FERC) and Energy Systems Associates (ESA). The purpose of these contracts is to have both the boiler manufacturer, C-E, and an independent contractor, FERC/ESA, evaluate and compare the boiler performance and emissions under the existing baseline conditions and retrofitted PM firing system.

Pertinent information on the furnace, firing system, and fuel at KP&L Lawrence No. 5 is shown in Table 1. Schematics of the existing windbox and the PM windbox for the Lawrence No. 5 unit are shown in Figure 14. The existing furnace was designed prior to the implementation of any NOx regulations. As such it does not include any NOx control techniques such as overfire air (OFA). There are five coal elevations and the associated normal auxiliary air and warm-up oil compartments.

The PM firing system retrofit includes four (4) completely new windboxes, separated OFA compartments, a new secondary air control system and a partial replacement of the coal piping. The new windboxes include five elevations of the PM firing nozzles. (An elevation of PM firing nozzles includes a fuel rich [Conc] and a fuel lean [Weak] nozzle.) The new windboxes also include integral close coupled OFA. The separated OFA includes two individually controlled compartments and has vertical and horizontal tilt adjustment capability. The main windbox and close coupled OFA has normal vertical tilt capability used for reheater steam temperature control. The extra windbox height for the PM firing system has been accommodated by extending the existing windbox location both lower and higher in the furnace waterwalls. Additional coal piping associated with the PM firing system coal pipe elbow separators was also included. The predicted NOx emissions with this design for the PM firing system and the coal type shown in Table 1 is less than 0.25 pounds NOx per million Btu fired or approximately one-half of the current New Source Performance Standards (NSPS) levels required for NOx.

The as found baseline boiler performance and emissions testing of the Lawrence No. 5 unit is currently underway. The installation of the PM firing system is scheduled for May and June of 1987. The parametric boiler performance and emissions evaluation of the PM firing system is scheduled to commence after the normal start-up period. Initial results from this testing should be available at the end of the third quarter of 1987.

C-E/MHI - MACT

No matter how closely the combustion process is controlled, the prerequisites for completing the combustion process (temperature, time, and excess oxygen) will be sufficient to generate at least some NOx. State of the art firing systems such as the PM burner can do an excellent job of burning pulverized coal as well as liquid and gaseous fuels, but there is always a minimal value below which further reduction in NOx is impractical. Thus, for very low NOx requirements, techniques have been developed to actually destroy NOx already formed by the combustion process. One such technique has been developed by MHI and subsequently licensed to C-E. This system is called MACT which is an abbreviation for Mitsubishi Advanced Combustion Technology (Ref. 7 and 10).

MACT is designed to take advantage of the high temperature kinetic characteristics of the nitrogen oxide molecule. Nitrogen oxide is relatively unstable at the elevated temperatures commonly found in the mid furnace sections of most modern pulverized coal fired boilers. Above 1200°C, the NO molecule can be "destroyed" by reacting with certain radicals at high temperatures. The high temperature chemistry is not in itself new, but what is unique to the MHI process reactions can be represented as follows:

$$C_nH_m + O_2 \rightarrow C_n'H_m'* + H_2O$$

$$NO + C_n'H_m'* \rightarrow C_n'' + NOx_2 + H_2O + CO$$

$$NO + C_n'H_m'* \rightarrow C_n''H_m'' + NH_i + H_2O + CO$$

The asterisks (*) denote a radical at the initial stage of chemical reaction and NH_i represents any nitrogen compound.

Conceptually, the MACT process can be seen in Figure 15. Compared to conventional firing systems, MACT diverts a small percentage of fuel from the main burner combustion zone and injects the fuel through UFI (Upper Fuel Injection) ports with an inert propellant, usually flue gas. The fuel injected into the "De-Noxing Zone" has insufficient oxygen to burn. Upon reaching sufficient temperature, the fuel generates, for a brief period of time, high temperature radicals which have such a high affinity for oxygen that they literally strip the oxygen from the NO molecule. This high temperature thermal decomposition of NO is called the "De-Noxing" (DN) process.

Since the fuel injected into the mid-furnace area in the DN process must be burned to completion to salvage the heating value of the fuel and to prevent hydrocarbon emission, the balance of the required combustion air is injected at the "AA" elevation (Figure 16). The "AA" process is the straightforward oxidation of the products of incomplete combustion leaving the DN process.

AA Process:

$$\begin{aligned} C_n\text{"}H_m\text{"} + O_2 &\;\text{->}\; H_2O + CO_2 \\ CO + O_2 &\;\text{->}\; CO_2 \\ NH_i + O_2 &\;\text{->}\; NOx_2 + H_2O \\ NH_i + O_2 &\;\text{->}\; NO + H_2O \end{aligned}$$

It is interesting to note that the last reaction shows the formation of NO. In both theory and practice, the MACT system does a very effective job of destroying most of the NO in the DN process but regenerates some of the NO in the "AA" process. The amount of NOx that is regenerated in the "AA" process is dependent on the fuel nitrogen content and reactivity of the reburn fuel. Natural gas, low nitrogen oil or low nitrogen high reactivity pulverized coal may be used as the deNOx or reburn fuel. This is significant because it means that MACT can be utilized in conjunction with conventional firing systems (tangential and wall fired) as well as with low NOx burner systems such as the PM burner to produce NOx concentrations on new boilers as low as 70 ppm to 115 ppm (vol. corrected to 3% O_2) firing pulverized coal.

MHI has had an oil fired PM/MACT combination in commercial service since January of 1981 in Japan. A 600 MW unit has been in operation since September of 1983 utilizing fuel oil as the "MACT fuel" and oil/pulverized coal in the main windbox - See Reference 10.

POST COMBUSTION CONTROL OF NOx

The NOx reduction capabilities of furnace combustion modifications are considerable. However, there are minimum levels at which further NOx reduction by these methods becomes impractical. With the use of dry catalytic tail end systems, reductions of up to 90% in NOx levels can be achieved.

Due to the stringent NOx regulations in Japan, Mitsubishi Heavy Industries, Ltd. (MHI) began developing a dry NOx removal process for its steam generating units in the early seventies. This was a developmental process in which the catalytic systems were first applied to natural gas fired units, then to low and high-sulfur oil fired units and finally to coal fired boilers. To complement existing C-E NOx reduction technology, a license agreement was signed with MHI in April 1980, making the catalytic and low NOx burner technology and products available to C-E for steam generators in the United States and Canada.

During the past few years, post combustion NOx control techniques utilizing selective catalytic reduction systems have been proposed for several industrial and cogeneration applications. The majority of these projects have been located in the Southern California area. In this region, the South Coast Air Quality Management District (SCAQMD) has imposed stringent NOx emission limitations. As a result of these restrictions, SCR systems have been proposed for meeting the NOx emission requirements for these new fossil fuel steam generating units.

In the spring of 1986, Combustion Engineering received a contract for a 250,000 lb/hr industrial boiler and SCR system at Chevron's El Segundo Refinery in El Segundo, California. The expected commercial operation date will be in the fall of 1987.

The SCR system for this unit is designed for natural gas, refinery gas and future no. 2 oil firing. The NOx emissions from the plant will be less than 9 parts per million by volume dry (ppmvd) at 3% O_2 for all proposed fuels. Additional space has been provided at the exit of the boiler to accommodate the future installation of a CO catalyst.

The SCR reactor chamber for this project will be located between the boiler and economizer section where suitable flue gas temperatures will be maintained for satisfactory SCR NOx reduction performance (see SCR general arrangement Figure 17). The flue gas from the boiler will flow vertically downward through the SCR reactor chamber. A single layer of modules composed of a number of standard, ceramic based, grid type catalytic elements will be furnished to treat the flue gas. An additional layer of modules will be required in the future to meet the NOx emission requirements for oil firing.

Upstream of the SCR chamber are the ammonia injection pipes, nozzles and mixing grid. Through orificed openings in the ammonia injection nozzles, a diluted mixture of ammonia gas in air is dispersed into the flue gas stream. This mixture is further distributed in the gas by a network of carbon steel pipework located downstream of the ammonia-air injection point. After the mixing grid, the ammonia flue gas mixture enters the reactor chamber where the catalytic reaction is completed.

The NOx reduction capabilities of furnace combustion modifications have practical limitations. When further NOx reduction is required, SCR systems have been proposed to attain these levels. Ultimately, the recommended NOx reduction technique for new or existing units will depend upon future NOx emission legislation.

SCR ECONOMICS

SCR systems are more expensive than in-furnace NOx control techniques. As shown in Figure 18, SCR systems for 80% NOx removal can add approximately 18% to the cost of a tangential coal fired unit with overfire air. In addition, the operating costs associated with an SCR must be evaluated. These expenses are tied to the auxiliary power requirements, ammonia supply costs and replacement costs of spent catalysts. The de-NOx fan, dilution air fan and instrumentation and controls are the main pieces of equipment contributing to the auxiliary power. For a 300 MW unit, the total estimated SCR related power consumption would be 700 Kw. Catalyst replacement costs will depend upon the actual service life of the catalyst.

At the present time, there are several coal fired utility SCR systems operating in Japan and western Europe (see Table 2). In Japan, excellent SCR experience has been achieved at Chugoku Electric Company - Shimonoseki Power Station No. 1. This unit has been in successful operation since April, 1980. It represents the first full scale coal fired SCR system in the world. The Shimonoseki unit is a 175 Mw coal fired boiler utilizing a grid type catalyst. The SCR system is designed for 50% NOx removal. Reference 13 represents an update on recent operating experience at this plant.

SCR Systems are optimally designed for 80% NOx removal. Removal efficiencies approaching 90% are possible, although such systems require significant increases in catalyst volume and cost.

The catalyst systems can be designed for both new or existing units. On retrofit applications, space requirements as well as existing fans, ductwork, air heaters and downstream equipment must be carefully evaluated before an SCR system can be accommodated. The boiler's structural integrity must also be checked due to the higher draft losses through the system. Each retrofit application is site specific.

CONCLUSION

The technology needed to comply with anticipated future NOx emission regulations is already commercially available. Furnace combustion modifications, post combustion catalytic systems or a combination of both methods may be considered for new or existing units depending upon the level of NOx emissions to be achieved. As shown in Figure 18, the relative costs of reducing NOx can vary significantly. Each method must be carefully analyzed to determine the most appropriate and cost effective technique for the desired NOx emission level.

DISCLAIMER

The work described in this paper was not funded by the U.S. Environmental Protection Agency and therefore the contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

REFERENCES

1. Lewis, R.D., et al, "Low NOx Coal Firing System Demonstration Results on a Tangentially Fired Boiler," presented at 1985 Joint Symposium on Stationary Combustion NOx Control, May 6-9, 1985, Boston, Massachusetts.

2. Kokkinos, A. and Lewis, R.D., "Field Evaluation of a Low NOx Firing System for Tangentially Coal-Fired Utility Boilers," Final Project Report, July 1985, EPA Report No. 600/7-85-018.

3. Kokkinos, A., et al, "Low NOx Firing System for Tangentially Coal-Fired Utility Boilers - Preliminary Testing," proceeding of the 1982 Joint Symposium on Stationary Combustion NOx Control, Vol. 1, July 1983, EPRI, Palo Alto, California 94302.

4. Sarjeant, M., et al, "Reductions in NOx Emissions from a 500 MW Corner-Fired Boiler," presented at the 1987 Joint Symposium on Stationary Combustion NOx Control.

5. Takahashi, T., et al, "Part I; Evaluation of Tangential Fired Low NOx Burner," proceeding of the 1982 Joint Symposium on Stationary Combustion NOx Control, Vol. 1, July 1983, EPRI, Palo Alto, California 94304.

6. Kokkinos, A., et al, "Part II; Feasibility Study of a Low NOx Retrofitable Firing System with U.S. Coals," proceeding of the 1982 Joint Symposium on Stationary Combustion NOx Control, Vol. 1, July 1983, Palo Alto, California 94304.

7. Takahashi, Y., et al, "Development of 'MACT' In-Furnace NOx Removal Process for Steam Generators."

8. Kawamura, T., Frey, D.J., "Current Development in Low NOx Firing Systems," Combustion Engineering, Inc., October 6, 1980, C-E TIS-6711.

9. Namiki, T., et al, "Application of a Pulverized Coal Fired NOx PM Burner for Steam Generators," presented at 1985 Joint Symposium on Stationary Combustion NOx Control, May 6-9, 1985, Boston, Massachusetts.

10. Murakani, N., et al, "Application of the "MACT" In-Furnace NOx Removal Process Coupled with a Low-NOx SGR Burner," presented at 1985 Joint Symposium on Stationary Combustion NOx Control, May 6-9, 1985, Boston, Massachusetts.

11. Sengoku, Tadamasa; Todo, Yoshinori; Yokoyama, Naruo; Howell, Brooks M.; "The Development of a Catalytic NOx Reduction System for Coal-Fired Steam Generators," presented at the Joint Symposium on Stationary Combustion NOx Control sponsored by EPA/EPRI, Denver, Colorado, October 6-9, 1980; Published at Combustion Engineering publication TIS-6710, 1980.

12. Mitsubishi Heavy Industries, Ltd., "Mitsubishi Dry Selective Catalysts NOx Removal System," MHI catalogue on SCR System, 1983.

13. Suyama, K., et al, "Operating Experience on a Selective Catalytic Reduction System for Steam Generators," presented at 1985 Joint Symposium on Stationary Combustion NOx Control, May 6-9, 1985, Boston, Massachusetts.

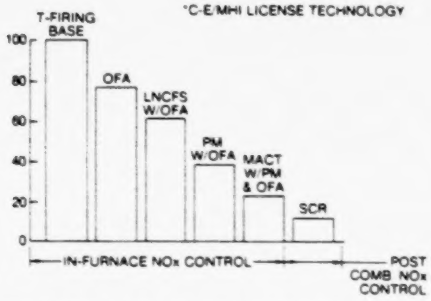
FIGURE 1

A Comparison of Various NO_x Reduction Techniques for Tangential Coal Fired Utility Boilers

KEY

T-FIRING	TANGENTIAL FIRING
OFA	OVERFIRE AIR
LNCFS	LOW NOx CONCENTRIC FIRING SYSTEM
*PM	POLLUTION MINIMUM BURNER
*MACT	MITSUBISHI ADVANCED COMBUSTION TECHNOLOGY
*SCR	SELECTIVE CATALYTIC REDUCTION SYSTEM

*C-E/MHI LICENSE TECHNOLOGY



100% BASE NOx LEVELS ARE EQUIVALENT TO PRE-1970 BOILER DESIGNS (TYPICAL NOx RANGE 0.5 - 0.7 LBS/10⁶ BTU)

FIGURE 2

Plan View of Tangentially Fired Steam Generator Flame Pattern

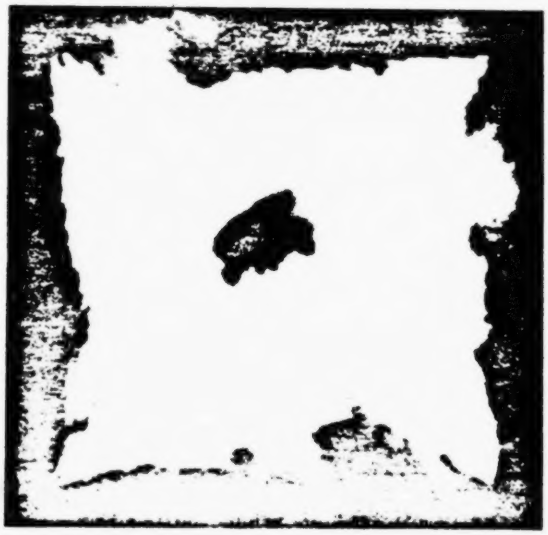


FIGURE 3

Typical Plan View of Fuel and Auxiliary Air Streams in Tangential Firing System

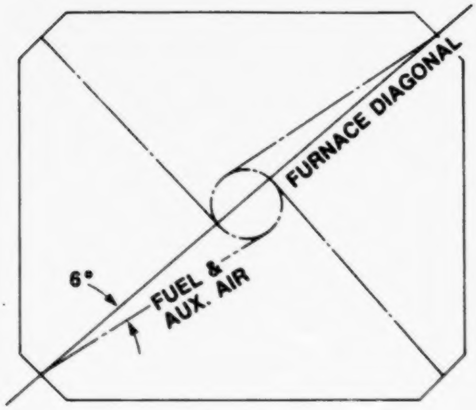

FURNACE DIAGONAL
6°
FUEL & AUX. AIR

FIGURE 4

Furnace Plan View - LNCFS

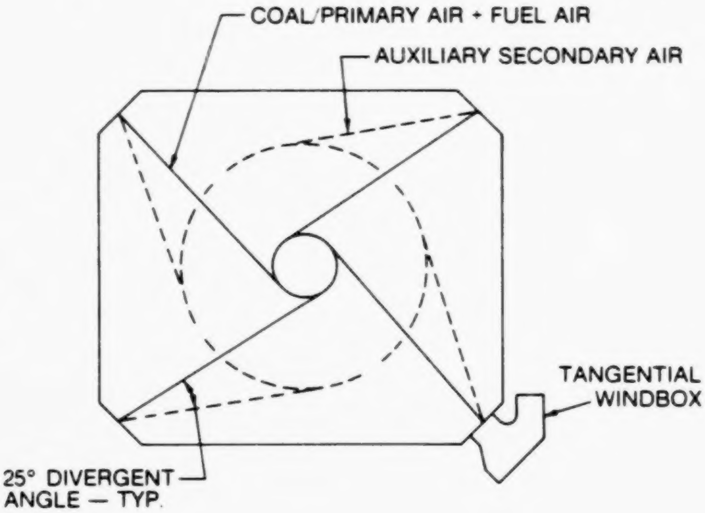

COAL/PRIMARY AIR + FUEL AIR
AUXILIARY SECONDARY AIR
TANGENTIAL WINDBOX
25° DIVERGENT ANGLE — TYP.

FIGURE 5

Air Nozzle Tip for LNCFS

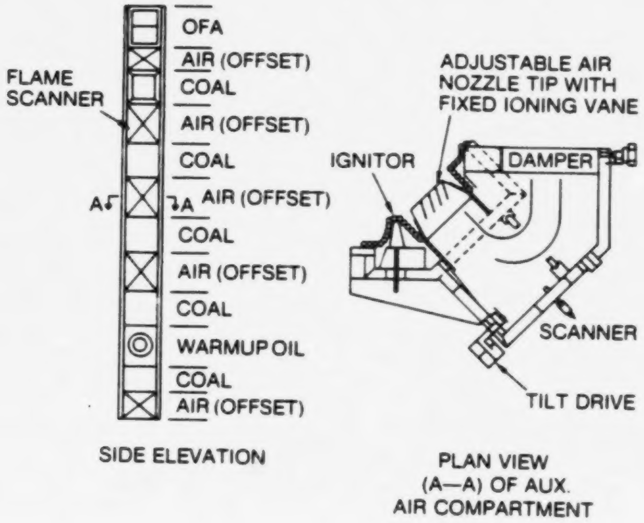

OFA
AIR (OFFSET)
COAL
AIR (OFFSET)
COAL
AIR (OFFSET)
COAL
AIR (OFFSET)
COAL
WARMUP OIL
COAL
AIR (OFFSET)
FLAME SCANNER
A
A
SIDE ELEVATION
ADJUSTABLE AIR NOZZLE TIP WITH FIXED IONING VANE
IGNITOR
DAMPER
SCANNER
TILT DRIVE
PLAN VIEW (A—A) OF AUX. AIR COMPARTMENT

FIGURE 6

Schematics of Unmodified and LNCFS Modofied Windboxes at CEGB Fiddlers Ferry Unit 1. (Not to Scale)

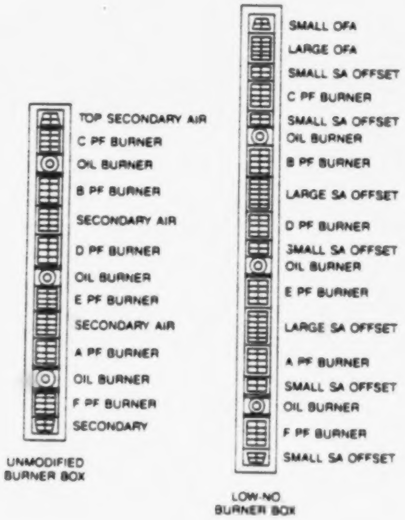

TOP SECONDARY AIR
C PF BURNER
OIL BURNER
B PF BURNER
SECONDARY AIR
D PF BURNER
OIL BURNER
E PF BURNER
SECONDARY AIR
A PF BURNER
OIL BURNER
F PF BURNER
SECONDARY
UNMODIFIED BURNER BOX
SMALL OFA
LARGE OFA
SMALL SA OFFSET
C PF BURNER
SMALL SA OFFSET
OIL BURNER
B PF BURNER
LARGE SA OFFSET
D PF BURNER
SMALL SA OFFSET
OIL BURNER
E PF BURNER
LARGE SA OFFSET
A PF BURNER
SMALL SA OFFSET
OIL BURNER
F PF BURNER
SMALL SA OFFSET
LOW-NO BURNER BOX

FIGURE 7

Typical NO_x Emissions Results from CEGB Fiddlers Ferry No. 1 with LNCFS and a Comparison Of These Results to Other Units

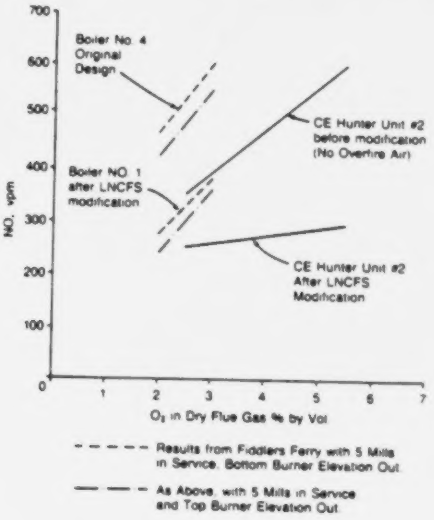


FIGURE 8

Concept of Pulverized Coal Fired Low-NO_x C-E/MHI PM Burner

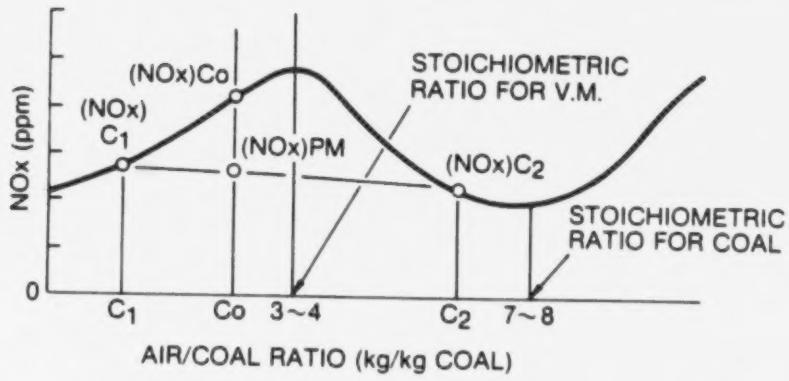


FIGURE 9

Structure of Coal fired Low-NO_x MHI/PM Burner

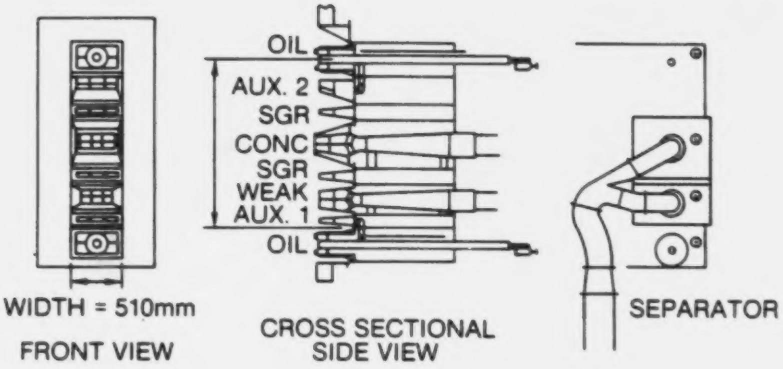

OIL
AUX. 2
SGR
CONC
SGR
WEAK
AUX. 1
OIL
WIDTH = 510mm
FRONT VIEW
CROSS SECTIONAL
SIDE VIEW
SEPARATOR

FIGURE 10

NO_x vs. OFA-MHI/PM Burner

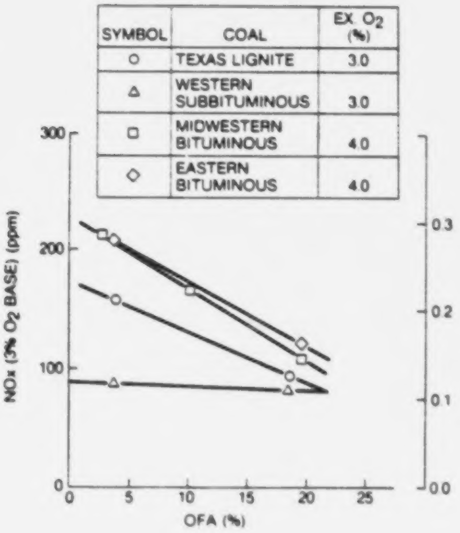


FIGURE 11

NO$_x$ vs. EX. O$_2$ (OFA = 20%) MHI/PM Burner

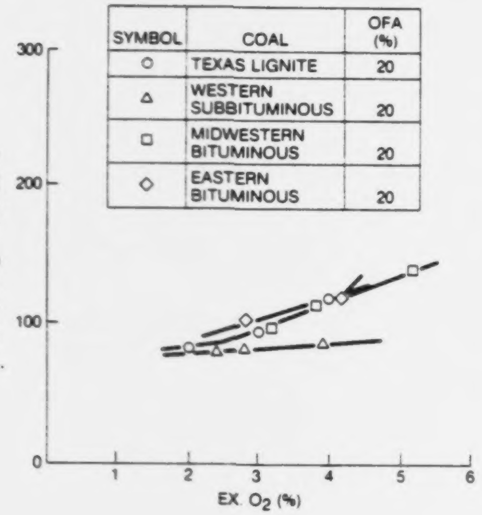


FIGURE 12

NO$_x$ vs. SGR MHI/PM Burner

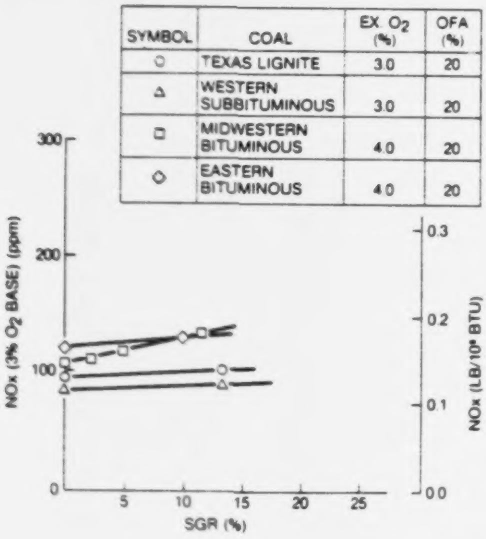


FIGURE 13

NO$_x$ vs. GM MHI/PM Burner

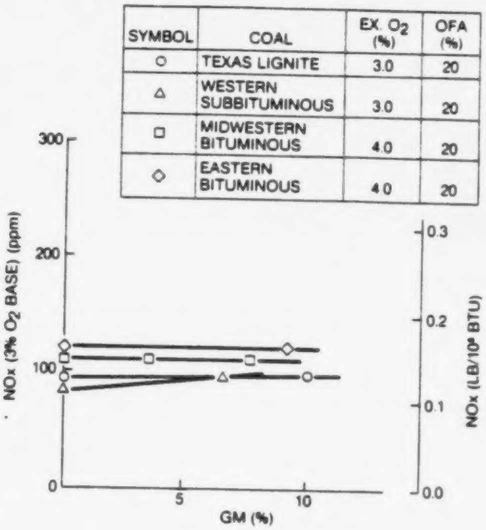


FIGURE 14

Schematics of Unmodified and PM Modified Windboxes at Kansas Power & Light Lawrence Unit No. 5

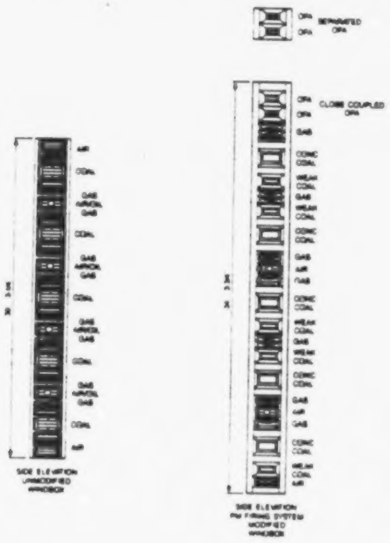

OFA
OFA
SEPARATED OFA
CLOSE COUPLED OFA
GAS
CONC COAL
WEAK COAL
AIR
COAL
SIDE ELEVATION UNMODIFIED WINDBOX
SIDE ELEVATION PM FIRING SYSTEM MODIFIED WINDBOX

FIGURE 15

Comparison of MACT In-Furnace NO_x Removal Process with Conventional OFA Method

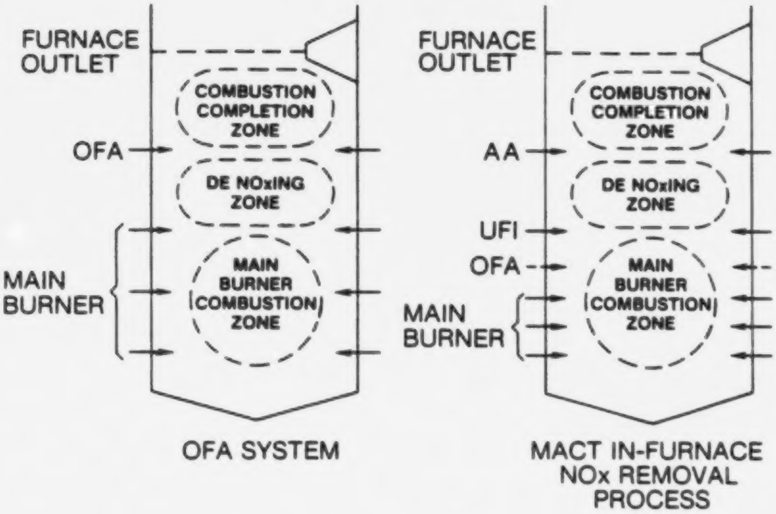

FURNACE OUTLET
COMBUSTION COMPLETION ZONE
OFA
DE NOxING ZONE
MAIN BURNER
MAIN BURNER (COMBUSTION) ZONE
OFA SYSTEM
FURNACE OUTLET
COMBUSTION COMPLETION ZONE
AA
DE NOxING ZONE
UFI
OFA
MAIN BURNER
MAIN BURNER (COMBUSTION) ZONE
MACT IN-FURNACE NOx REMOVAL PROCESS

FIGURE 16

Schematic Diagram of MACT for Steam Generator

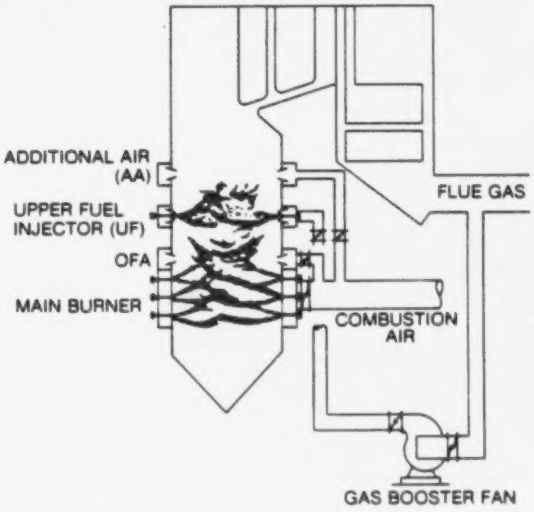

ADDITIONAL AIR (AA)
UPPER FUEL INJECTOR (UF)
OFA
MAIN BURNER
FLUE GAS
COMBUSTION AIR
GAS BOOSTER FAN

FIGURE 17

TYPICAL SCR PLANT ARRANGEMENT

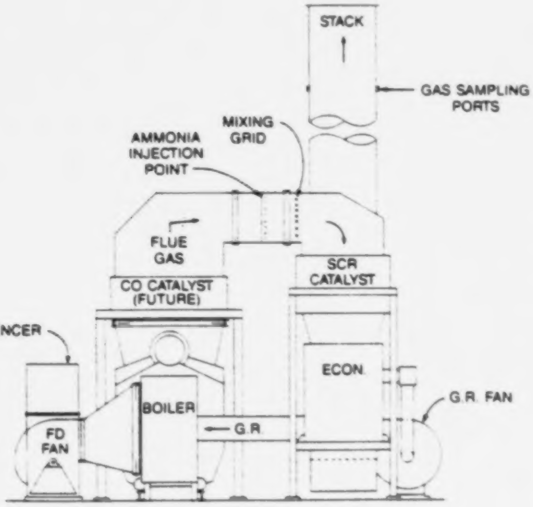

STACK
GAS SAMPLING PORTS
MIXING GRID
AMMONIA INJECTION POINT
FLUE GAS
SCR CATALYST
CO CATALYST (FUTURE)
SILENCER
ECON.
G.R. FAN
BOILER
G.R.
FD FAN

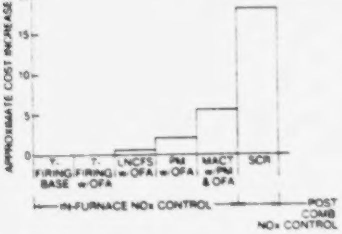
FIGURE 18

Economic Comparison of Various NO_x Reduction Techniques for Tangential Coal Fired Utility Boilers

KEY

T-FIRING	TANGENTIAL FIRING
OFA	OVERFIRE AIR
LNCFS	LOW NOx CONCENTRIC FIRING SYSTEM
*PM	POLLUTION MINIMUM BURNER
*MACT	MITSUBISHI ADVANCED COMBUSTION TECHNOLOGY
*SCR	SELECTIVE CATALYTIC REDUCTION SYSTEM

*C-E/MHI LICENSED TECHNOLOGY



NOTES

1 BASED ON MATERIAL AND CONSTRUCTION COSTS FOR A NEW 300 Mw COAL FIRED UNIT

2 SCR SYSTEM COSTS ARE BASED ON 80% NOx REMOVAL

3 SCR SYSTEM COSTS DO NOT INCLUDE NH_3 TANK FARM EQUIPMENT OR EXTERNAL STRUCTURAL SUPPORT STEEL

4 THESE COST APPROXIMATIONS ARE SUBJECT TO CHANGE DEPENDING ON SPECIFIC UNIT DESIGN REQUIREMENTS

TABLE 1
KANSAS POWER & LIGHT COMPANY
LAWRENCE UNIT NO. 5

GENERATOR RATING	400 MWe
MAXIMUM STEAM FLOW	2,805,000 lb/hr
SUPERHEAT STEAM TEMPERATURE/PRESSURE	1005°F/2620 psig
FURNACE WIDTH	50' - 8"
FURNACE DEPTH	40' 2-1/8"
FIRING SYSTEM	TILTING TANGENTIAL
PULVERIZERS	FIVE 743RS (WITH EXHAUSTERS)

FUEL ANALYSIS:	
MOISTURE	10.5 %
VOLATILE MATTER	38.0 %
FIXED CARBON	42.9 %
ASH	8.6 %
H	4.50%
C	61.91%
S	0.47%
N	1.27%
O	12.75%
ASH	8.60%
MOISTURE	10.50%
HHV	10,884 Btu/lb

TABLE 2

EXPERIENCE LIST OF SCR SYSTEMS FOR
COAL FIRED UTILITY BOILERS

	Plant Name	Plant Output	Catalyst Type	Start of Operation
1.	Chugoku Electric Shimonoseki P/S No. 1	175 MW	Grid Honeycomb	Apr. 1980
2.	Chugoku Electric Shin-ube P/S No. 1	75 MW	Grid Honeycomb	Dec. 1981
3.	Chugoku Electric Shin-ube P/S No. 2	75 MW	Grid Honeycomb	Nov. 1981
4.	Chugoku Electric Shin-ube P/S No. 3	156 MW	Grid Honeycomb	Sept. 1981
5.	Joban Joint Electric Nakoso P/S No. 8	600 MW	Grid Honeycomb	Jul. 1983
6.	Kyushu Electric Minato P/S No. 1	156 MW	Grid Honeycomb	Apr. 1983
7.	Shikoku Electric Shinsaijo P/S No. 1	156 MW	Grid Honeycomb	Mar. 1983
8.	Sakata Electric Sakata P/S No. 1	350 MW	Grid Honeycomb	Jul. 1983
9.	Sakata Joint Electric Sakata P/S No. 2	350 MW	Grid Honeycomb	
10.	Tokyo Electric Yokosuka P/S No. 1	265 MW	Grid Honeycomb	Jan. 1984
11.	Tokyo Electric Yokosuka P/S No. 2	265 MW	Grid Honeycomb	May 1984
12.	Kyushu Electric Matsuura P/S No. 1	700 MW	Grid Honeycomb	Jun. 1986
13.	Hokuriku Electric Tsuruga P/S No. 1	500 MW	Grid Honeycomb	1990
14.	VKR Knepper Unit No. C (THYSSEN)	375 MW x 1/4	Grid Honeycomb	Jul. 1986
15.	TWS Munster No. 15 (EVT)	50 MW	Grid Honeycomb	May, 1986
16.	EVS Heilbronn P/S (EVT)	700 MW	Grid Honeycomb	Sept. 1986
17.	TWS Munster No. 12 (EVT)	50 MW	Grid Honeycomb	Sept. 1986
18.	TWS Munster No. 25 (EVT)	250 T/H	Grid Honeycomb	Aug. 1988
19.	GKM (Gross Kraftwerk Mannheim AG) Spare Equipment Shop 1 Block 7, No. 18 (EVT)	1370 T/H	Grid Honeycomb	Mar. 1988
20.	Steweag Mellach P/S (SGP)	200 MW	Grid Honeycomb	Oct. 1986
21.	PGEM Centrale Gelderland (ESTS)	130 MW x 1/2	Grid Honeycomb	Jan. 1987

C-E USA EXPERIENCE

Chevron, Inc. Richmond, California	3 Gas Fired Process Heaters	Grid Honeycomb	Jul. 1984
Chevron, Inc. El Segundo Refinery	250000 lb/hr Industrial Boiler	Grid Honeycomb	Oct. 1987

UPDATE OF NO_x CONTROL TECHNOLOGIES AT RILEY STOKER

C.E. McHale
R.A. Lisauskas
Riley Stoker Corporation

ABSTRACT

Recent design and operating experience with Riley Stoker low-NO_x combustion systems in pilot scale and commercial furnaces is reviewed. The performance of several commercial low-NO_x burner installations in wall- and Turbo-fired furnaces is described. Both emissions reductions from uncontrolled levels and the impact of the combustion process modifications on furnace temperatures are discussed. Pilot scale results focus on in-furnace NO_x and SO_2 control processes such as reburning and sorbent injection.

Recent activities include CCV burner design refinements, and developing staged combustion systems for utility boilers, industrial stoker-fired boilers and circulating fluidized bed combustors. Since jet aerodynamics influence combustion and NO_x reduction efficiencies, two-phase jets in furnace enclosures are discussed.

INTRODUCTION

In the past several years, interest in NO_x control has broadened to include a wider range of technologies and fuels. Because of the relatively stable boiler population, retrofit NO_x controls have become increasingly important for both large industrial and utility boilers. Combustion controls such as low NO_x burners and overfire air systems appear to be significantly more cost effective than post combustion control techniques. The recent promulgation of new federal NO_x standards for boilers below $250x10^6$ Btu/hr in size will require the implementation of controls on smaller industrial boilers. Riley Stoker Corporation has recently field tested new NO_x control combustion systems on industrial coal-fired Turbo, as well as straight wall boiler designs. As a result of major changes in fuel prices, there is also renewed interest in NO_x controls for gas and oil-fired boilers. This interest applies to both the industrial and utility sectors.

In addition to traditional boiler systems, new technologies are being developed to utilize other types of fuels. New stoker-fired resource recovery boilers are being constructed and brought on-line to burn waste fuels such as municipal solid waste (MSW) and refuse derived fuels (RDF). The number of such resource recovery systems in the U.S. is expected to increase dramatically over the next five to ten years. Commercial fluidized bed boiler systems are also emerging in both industrial and utility boiler applications. Fluidized bed combustion systems have the unique ability to burn a wide variety of fuels with reduced emissions. There is a growing awareness that along with the destruction of harmful toxic materials, air emissions such as NO_x must be controlled during waste incineration.

Recent commercial applications of combustion modifications for NO_x reduction have raised system operation and design concerns. Low NO_x operation has the potential to adversely affect both performance and unit life. Pilot and full-scale efforts are underway to identify and assess these impacts, and to develop practical solutions.

The following is a summary of recent Riley experience and efforts to develop NO_x control technology for a variety of boiler combustion systems.

LOW NO_x BURNER FIELD TESTS

Riley Stoker manufacturers two low-NO_x burner systems: the Controlled Combustion Venturi (CCV) burner (U.S. Patent No. 4,479,442) for wall-fired boilers, and the Tertiary Staged Venturi (TSV) system (U.S. Patent No. 4,517,904) for Turbo furnaces. Both systems have been operating at utility and industrial installations for several years. Typical NO_x emissions achieved with these systems are summarized in Figure 1. Details of recent field experience with these burners follow.

The Controlled Combustion Venturi (CCV) burner was originally developed for retrofit on pulverized coal wall-fired boilers. NO_x control is achieved through a patented venturi coal nozzle design, which utilizes both a venturi section and a four bladed coal spreader to control fuel/air mixing. This nozzle design provides swirl to the primary air/coal stream, while separating the stream into fuel-rich and fuel-lean layers before mixing with the secondary air. Results of a recent utility test program on the CCV burner are presented in Figure 2. Since this unit also has an overfire air system, we obtained data at primary zone stoichiometries between 1.0 and 1.2. The data demonstrate that the burners are operating in the field as predicted by recent Riley, EPA and EPRI $100x10^6$ Btu/hr test programs (1,2,3).

Mechanical improvements to the CCV burner are also being developed. This burner was originally designed as a replacement coal nozzle and spreader for our pre-NSPS Flare burner design. No modifications in the Flare burner secondary air system are made in the retrofit. We are now developing a new secondary air register and control system for the CCV burner. Our objective is to design a new generation burner that is easier to operate and reliable over a wide range of register settings. This is important since pilot and field testing have shown that achieving low-NO_x emissions and effective carbon burnout depends upon consistently controlling secondary air design conditions. The new generation CCV burner system will be tested in our $100x10^6$ Btu/hr combustion test facility this year. A single burner will then be installed in a 300 MW boiler and operated for a year to evaluate its reliability in a commercial application.

Experience with the CCV burner and staged combustion systems led to the development of a low-NO_x burner for Turbo-fired systems, the Tertiary Staged Venturi (TSV) burner. The TSV burner has a coal nozzle and spreader assembly resembling the CCV burner. The TSV burner is designed for two stage combustion. It operates with a fuel rich recirculation zone near the burner throat (40 to 70% of theoretical air). Four tertiary air ports equipped with directional vanes are used to raise the total burner front stoichiometry between 70 and 100% of theoretical air. The balance of the combustion air is provided through the overfire and underfire air systems shown in Figure 3. NO_x emissions of 300 ppm have consistently been achieved with this system in large industrial boiler operations.

IMPROVED OVERFIRE AIR SYSTEMS

Overfire air is an important application of staged combustion to reduce NO_x emissions in utility and industrial boilers. It is also used to control furnace temperatures and burnout in stoker-fired industrial systems. In all of these applications, a thorough understanding of the mixing process between the overfire air and combustion zone products is critical to achieving desired system performance. Riley has been employing both computational fluid dynamics and laboratory flow modeling to design overfire air systems for a variety of firing systems.

Riley will install a new air staging system on a 425 MWe Turbo-fired boiler in April. The design objectives were: 1) increase boiler load to 105% Maximum Continuous Rating (MCR); 2) reduce NO_x emissions to 0.65 $lb/10^6$ Btu while overfiring; and 3) achieve efficient carbon burnout with the low NO_x combustion system. An additional objective was utilizing as much of the existing equipment as possible to minimize retrofit costs.

Our design to achieve these objectives requires modification of the existing 24 Directional Flame burners, and diversion and control of additional combustion air to the air staging system. The existing overfire air system is being upgraded to include separate overfire air ductwork with a new air control system. Underfire air ports are being installed to provide additional staging and improve lower furnace combustion efficiency. Extensive computer simulations were performed to design the staging system and predict performance.

The location of the overfire air ports in the furnace venturi, combined with the Turbo furnace burner flow pattern, readily allows separating the final OFA combustion zone from the primary burner zone. However, the proximity of the underfire air (UFA) ports to the burners is critical. If the underfire air ports are too close to the burners, UFA will be entrained rapidly into the main combustion product flow. If this occurs, minimal staging will be achieved and final NO_x reductions could be disappointing. Burnout considerations require well-controlled mixing of all three flow streams. To further improve burnout efficiency, additional wing overfire air ports have been installed near the furnace side walls. Flow model studies (4) suggest that the increased mixing achieved with these wing ports promotes carbon burnout under staged firing conditions.

A computational fluid dynamics code that predicts temperatures, flow streamlines, turbulence parameters, and post-combustion oxygen concentrations was used to analyze the furnace performance impacts of these combustion system modifications. An isometric view of the furnace section studied in the computer model is shown in Figure 4. Figure 5 presents some results of this analysis. The temperature profiles shown predict no major changes in furnace temperatures will occur when this retrofit is completed. Similar profiles of staged air jet penetration and jet velocities were generated during the design study.

RESOURCE RECOVERY

Riley has been active in the design and manufacture of resource recovery boiler systems for many years. In 1968, Riley supplied a municipal solid waste (MSW) fired stoker and recovery boiler to the Town of Braintree, Masachusetts. The design of stoker-fired systems for waste fuels is subject to several constraints. Waste fuels such as MSW have widely variable heating values and moisture contents. Refuse systems, therefore, require a flexible combustion air system to insure complete combustion and to minimize the formation of pollutants such as CO and NO_x. Overfire air is often used in these stoker-fired systems to enhance incineration, combustion flexibility, and control. The same computer code used to analyze OFA systems for suspension fired systems is also being used to evaluate the effectiveness of OFA in stoker-fired refuse systems. Figure 6 represents oxygen profiles computed for a traveling grate stoker firing a refuse derived fuel (RDF). Comparing these oxygen concentration profiles is an invaluable tool in evaluating furnace mixing and in designing efficient combustion systems for the destruction of toxic constituents in these waste fuels.

In 1984, Riley obtained the exclusive American license for an advanced step grate stoker refuse combustion system from Takuma Co. Ltd. of Japan. Since 1963, Takuma has installed some 250 resource recovery MSW systems throughout Japan. These facilities represent a combined capacity in excess of 50,000 tons per day. The first Riley/Takuma boiler system is currently undergoing start-up and testing in Olmsted, Minnesota.

The Riley/Takuma combustion system includes both a step grate stoker design and an automatic combustion control system (5). Schematic diagrams of the combustion system, and the combustion air and oxygen control system are shown in Figures 7a and 7b. Three grates, with individual undergrate air control systems, are used to promote drying and ignition, combustion, and burnout. Approximately 20% of the combustion air is provided by the overfire air system. Multiple levels of overfire air jets are used to control both mixing above the grate and furnace temperature. The combustion control system combined with grate speed and furnace control systems provide the flexibility to burn a variety of MSW fuels regardless of source, season, and geographic origin.

To insure complete combustion, MSW systems operate with excess air levels of 80% or more. The automatic oxygen control system serves to minimize furnace O_2 levels for improved combustion efficiency and lower NO_x emissions. NO_x emissions of 100 ppm (at 12% O_2) and lower have been acheived under this mode of operation. A number of combustion modification techniques can also be used on commercial MSW systems to further control NO_x. Water injection above the grate has achieved NO_x reductions of 20% and greater. The same level of NO_x control has also been attained with 20 to 30% flue gas recirculation (FGR). FGR has the added benefit of reducing excess air requirements. Takuma is also evaluating and testing several in-furnace NO_x reduction techniques including ammonia and urea injection. In addition, Riley and Takuma are currently evaluating an integrated NO_x control concept based on natural gas co-firing.

FLUIDIZED BED BOILERS

Atmospheric fluidized bed combustion offers another route for achieving both low NO_x and SO_2 emissions without post combustion flue gas treatment. Riley currently designs and manufacturers fluidized bed boiler systems based on an advanced circulating fluidized bed combustion technology known as Multi-Solid Fluidized Bed Combustion (MSFBC). MSFBC boiler systems are supplied in the U.S. by Riley under a license agreement with Battelle Development Corporation.

The MSFBC system, shown in Figure 8, is a two stage combustion process (6). It consists of an entrained bed of fine ash and limestone particles superimposed on a fluidized dense bed of large particles. The lower dense bed of large particles serves to promote mixing and increase the residence time of entrained ash, fuel and limestone. The combustor operates in a fast fluidized bed mode with superficial gas velocities of 30 to 35 ft/sec. Heat transfer and combustion are decoupled in this system. Heat recovery occurs in an external heat exchanger and a convective boiler. The external heat exchanger actually consists of heat exchange tubes immersed in a conventional low velocity fluidized bed. Combustion temperature is controlled between 1500 and 1700°F by recycling entrained ash through the external heat exchanger.

Low combustion temperatures and a two stage design offer the potential for achieving NO_x emissions significantly lower than current NSPS requirements. MSFBC systems are operated with the lower dense bed of the combustor under fuel rich conditions. Carbon burnout is completed in the upper oxidation zone. As in other staged combustion systems, the three most important variables affecting NO_x control in a MSFBC system include: (1) primary zone stoichiometry, (2) primary zone residence time, and (3) primary zone temperature.

The importance of each of these variables on MSFBC NO_x emissions is shown in Figure 9. Coal-fired pilot scale data and data from a 50×10^6 Btu/hr field unit are presented for a wide range of operating conditions. Given sufficient primary zone residence time under proper fuel rich conditions, NO_x emission levels approaching 0.1 lb/10^6 Btu can be achieved. In MSFBC systems, primary zone temperature is controlled by adjusting the solids recycle rate to the lower combustor. In addition to these primary control variables, a secondary NO_x dependence has been observed with fuel particle size, fuel nitrogen content, and excess air level.

Riley continues to design and develop MSFBC systems for new and increasingly larger boiler applications. MSFBC systems are capable of burning a wide range of waste materials, as well as coal. Its two stage design makes MSFBC well suited for the combustion of difficult to burn high nitrogen species. Currently, there are ten MSFBC boiler installations, ranging in size from 50,000 to 625,000 lb/hr of steam, either operating, undergoing start up, or under design and construction throughout the world.

PILOT SCALE STUDIES

Riley is continuing to evaluate combustion modification techniques that can be retrofit to existing industrial and utility boiler systems. In addition to the $100x10^6$ Btu/hr Coal Burner Test Facility (CBTF), the Riley Research Center recently began operating a $3x10^6$ Btu/hr Pilot Scale Combustion Facility (PSCF). The PSCF is designed to simulate thermal conditions throughout the radiant and convective passages of a boiler. This new facility is equipped with air cooled tube banks to represent various convective heat transfer surfaces from superheater to the economizer. The PSCF has been used to investigate both in-furnace SO_2 and NO_x control techniques. SO_2 removal characteristics for both furnace injected limestone and dolomite as measured in the PSCF are shown in Figure 10. The temperature profile and sorbent injection location maintained during combustion tests on a high sulfur (3.9%) Kentucky bituminous coal is shown in Figure 11. Quench rates in the sulfactor reaction window (2300 to 1600°F) were on the order of 300°F/sec. This condition is typical of many full scale furnaces.

The PSCF has also been used to evaluate advanced NO_x control concepts such as reburning. Figure 12 summarizes the results of NO_x emissions when natural gas is injected as the reburn fuel above a pulverized coal flame. NO_x emissions are shown as a function of reburning zone stoichiometry. Uncontrolled NO_x emissions for these tests were approximately 550 ppm. Reburning zone residence times ranged from 400 to 700 milliseconds. Figure 10 also compares PSCF results with results obtained in Riley Research's $100x10^6$ Btu/hr burner test facility using coal as the reburn fuel (2). Final NO_x emissions in both cases are similar. However, in coal-fired applications where upper furnaces residence times are limited, the use of gas or oil as the reburning fuel may be preferable since faster combustion rates can be obtained.

SUMMARY

Riley Stoker is developing NO_x control systems for a wide range of boiler designs and fuel types. Combustion controls such as low NO_x burners and overfire air systems are being installed on utility and industrial wall-fired and Turbo-fired units. In addition to these traditional boiler systems, new technologies which utilize other types of fuels are being developed. These include a circulating fluidized bed and stoker-fired resource recovery boilers to burn waste fuels.

Combustion process modification techniques such as air staging are common to all of these boiler systems. Evaluations of staged combustion operation are focusing on two areas: determining the optimum amount of staging air to limit pollutant formation, and optimizing the staging system design to maintain burnout and furnace temperature requirements. Three dimensional computer simulations of the turbulent mixing processes in overfire air applications are being used to establish commercial system designs. In addition, sorbent injection systems for in-furnace sulfur emissions control and reburning with natural gas as the staging fuel have been evaluated in our pilot scale combustion facility. Future plans include evaluating stoker firing systems in this test furnace. This combination of experimental and analytical evaluations is enabling Riley to design commercial NO_x control systems for a broad range of combustion system configurations and fuel types.

REFERENCES

1. Penterson, C.A. Development of an Economical Low NO_x Firing System for Coal Fired Steam Generators. Presented at the ASME Joint Power Generation Conference, Denver, October, 1982.

2. Lisauskas, R., Snodgrass, R., Johnson, S., and Eskinazi, D. Experimental Investigation of Retrofit Low NO_x Combustion Systems. In: Proceedings of the 1985 Joint Symposium on Stationary Combustion NO_x Control.

3. Lisauskas, R., Itse, D., and Masser, C. Extrapolation of Burner Performance from Single Burner Tests to Field Operation. In: Proceedings of the 1985 Joint Symposium on Stationary Combustion NO_x Control.

4. Lisauskas, R., McHale, C., Afonso, R., and Eskinazi, D. Development of Overfire Air Design Guidelines for Single Wall Fired Boilers. Presented at the 1987 Joint Symposium on Stationary Combustion NO_x Control, New Orleans, March, 1987.

5. Palacios, F.A. and Wakamura, Y. Automatic Combustion Control of Mass Fired Refuse Incineration Plant. Presented at the International Public Works Congress and Equipment Show, Los Angeles, September, 1985.

6. Nack, H., Litt, R.D. and Kim, B.C. Multisolid Fluidized Bed Combustion. Chemical Engineering Progress, January 1984.

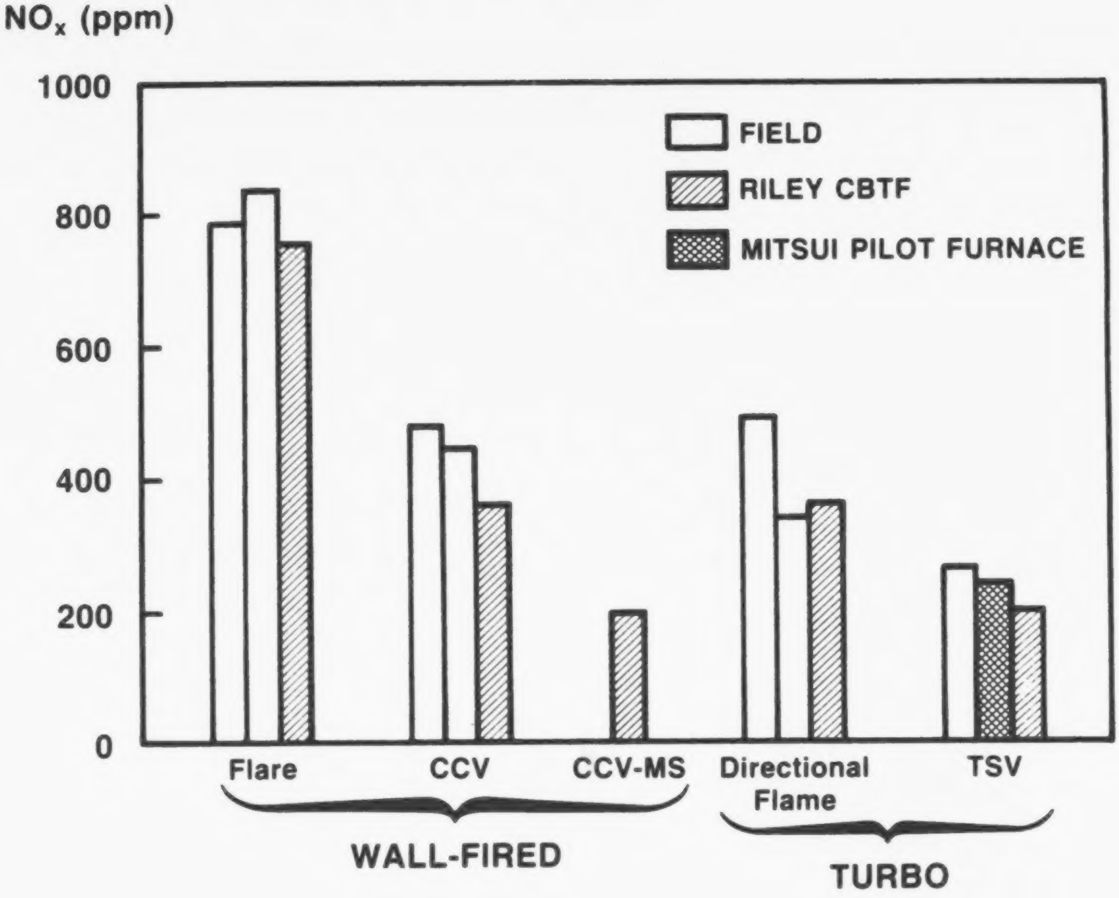


Figure 1. Burner Performance Comparison

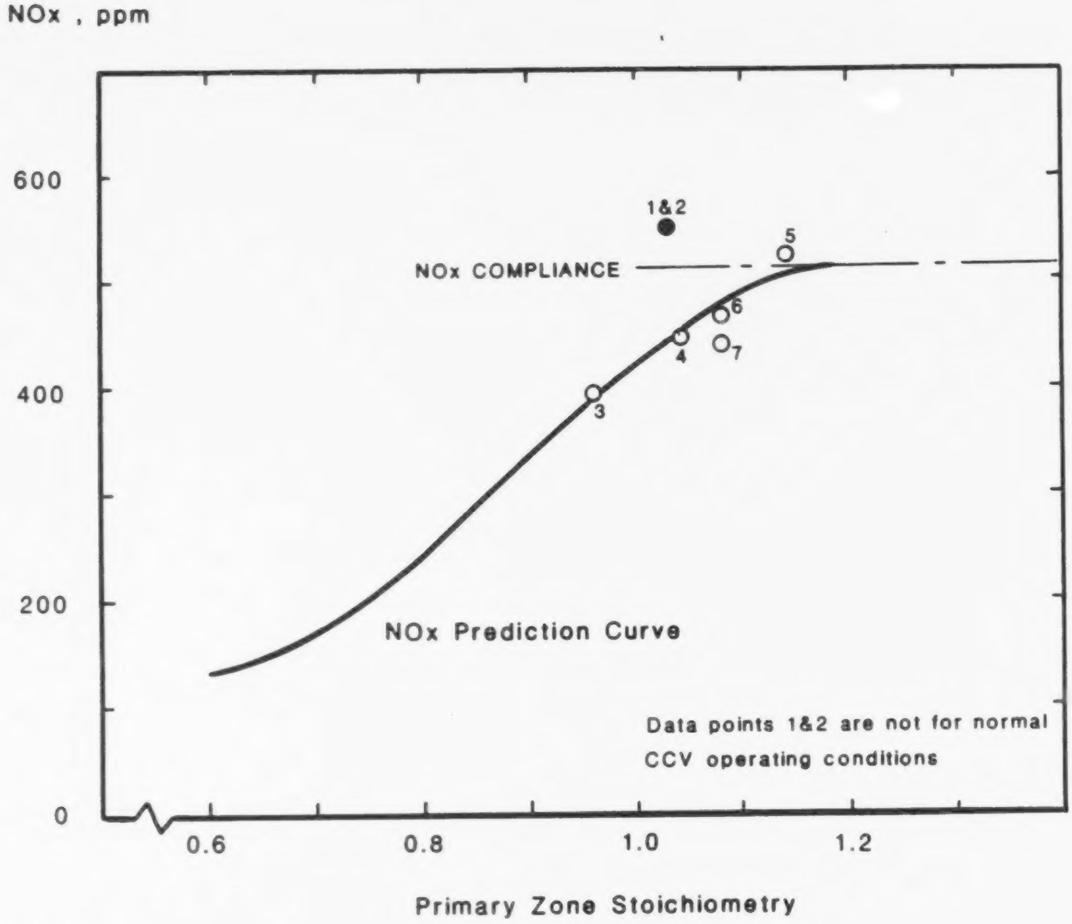


Figure 2. CCV Burner Performance at a 360 MWe Unit

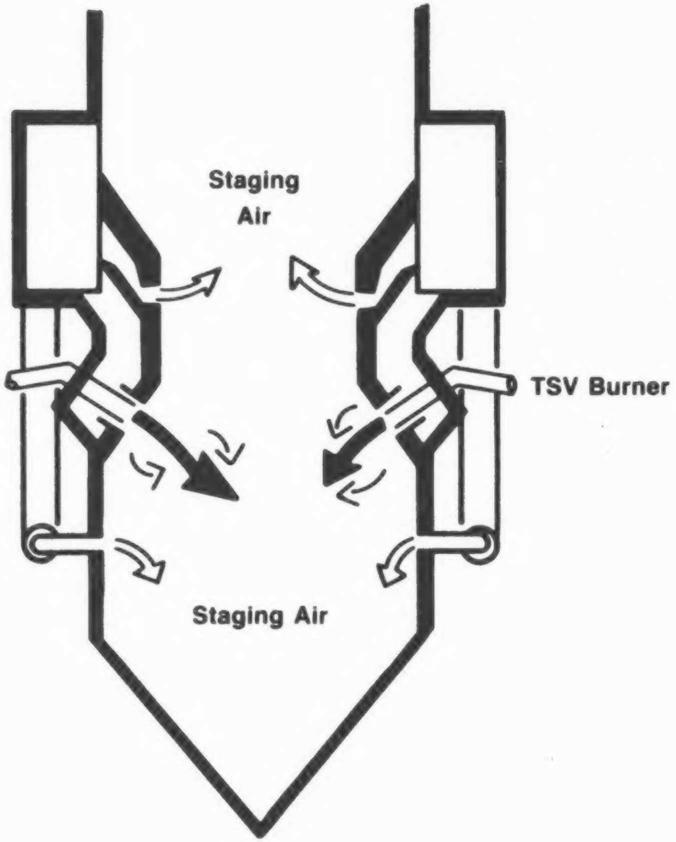

Staging
Air
TSV Burner
Staging Air

Figure 3a. Advanced Turbo Furnace Staging System

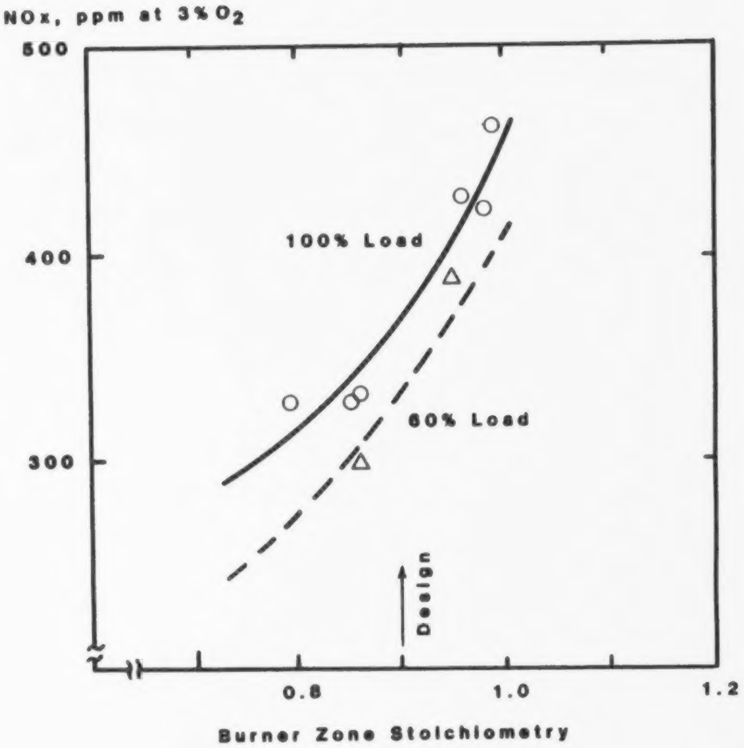


Figure 3b. NOx vs. Burner Zone Stoichiometry for the TSV System (Coal Firing at 100% and 60% Load)

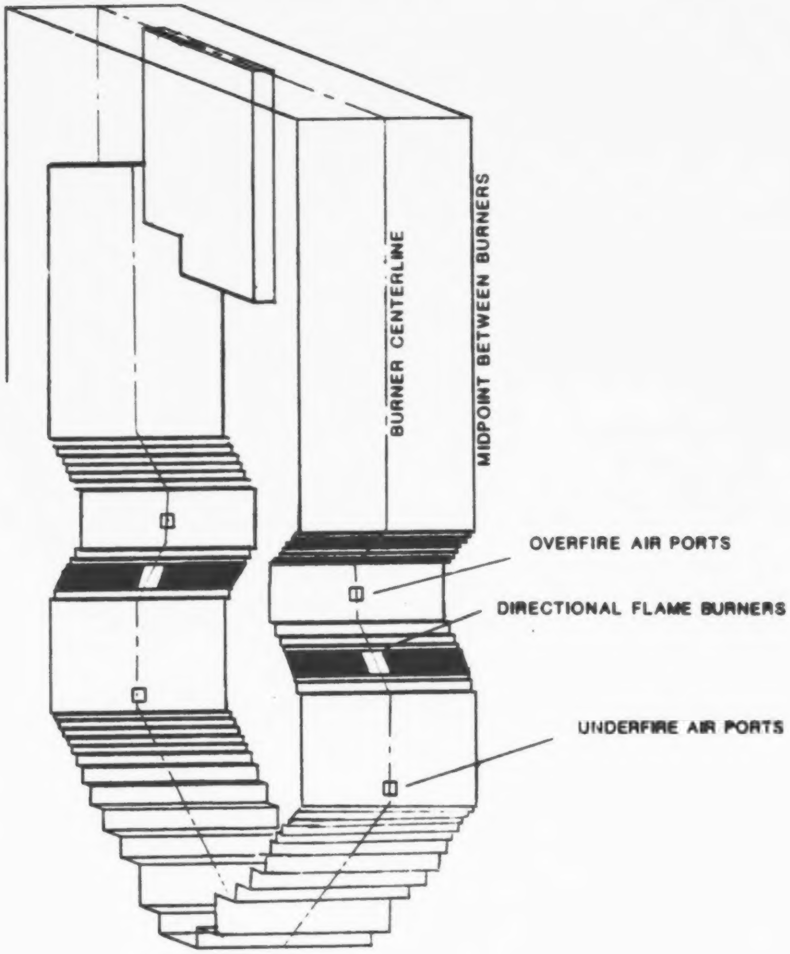

BURNER CENTERLINE
MIDPOINT BETWEEN BURNERS
OVERFIRE AIR PORTS
DIRECTIONAL FLAME BURNERS
UNDERFIRE AIR PORTS

Figure 4. Isometric View of Furnace Modeling Domain

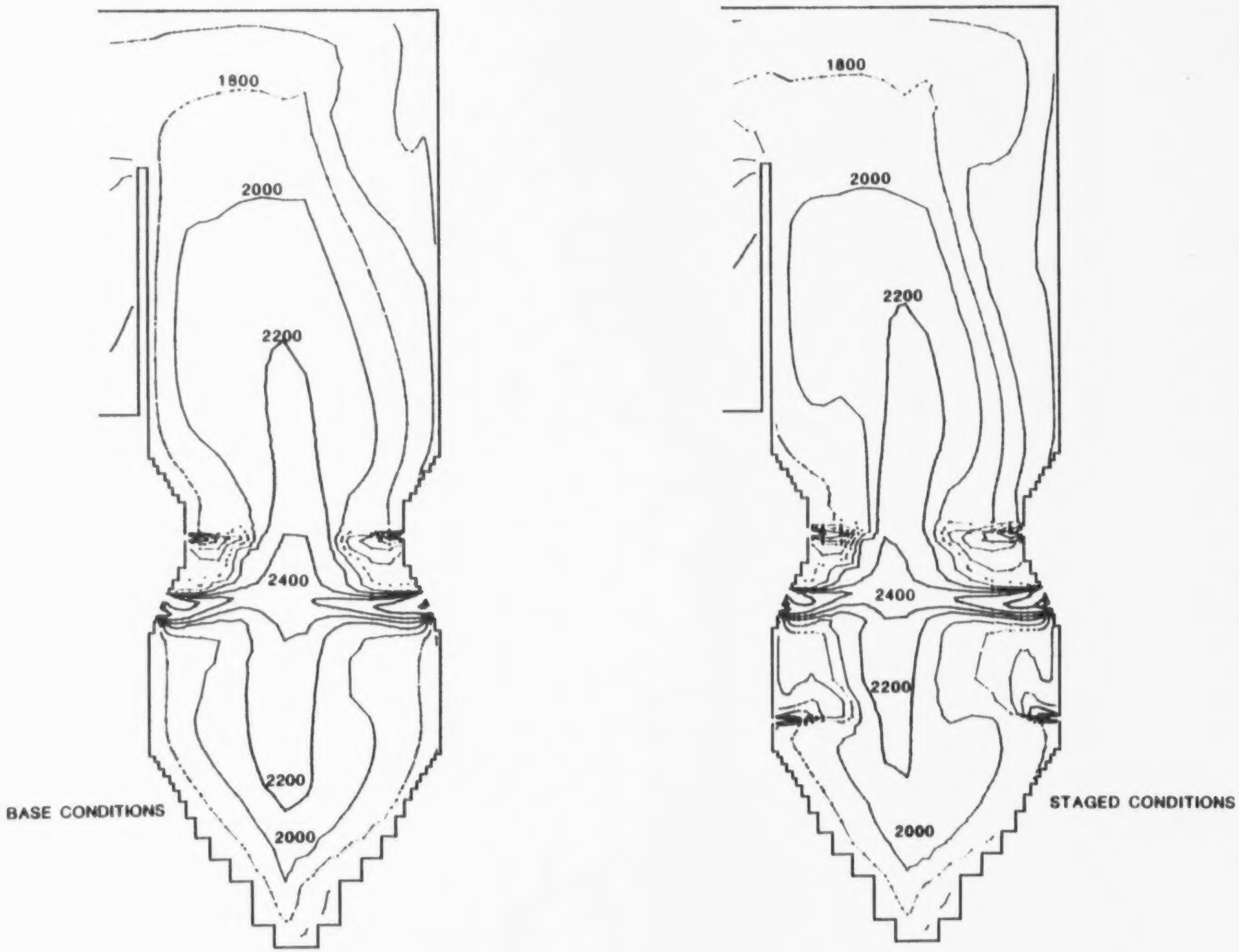


Figure 5. Temperatures for Original and Staged Operating Conditions

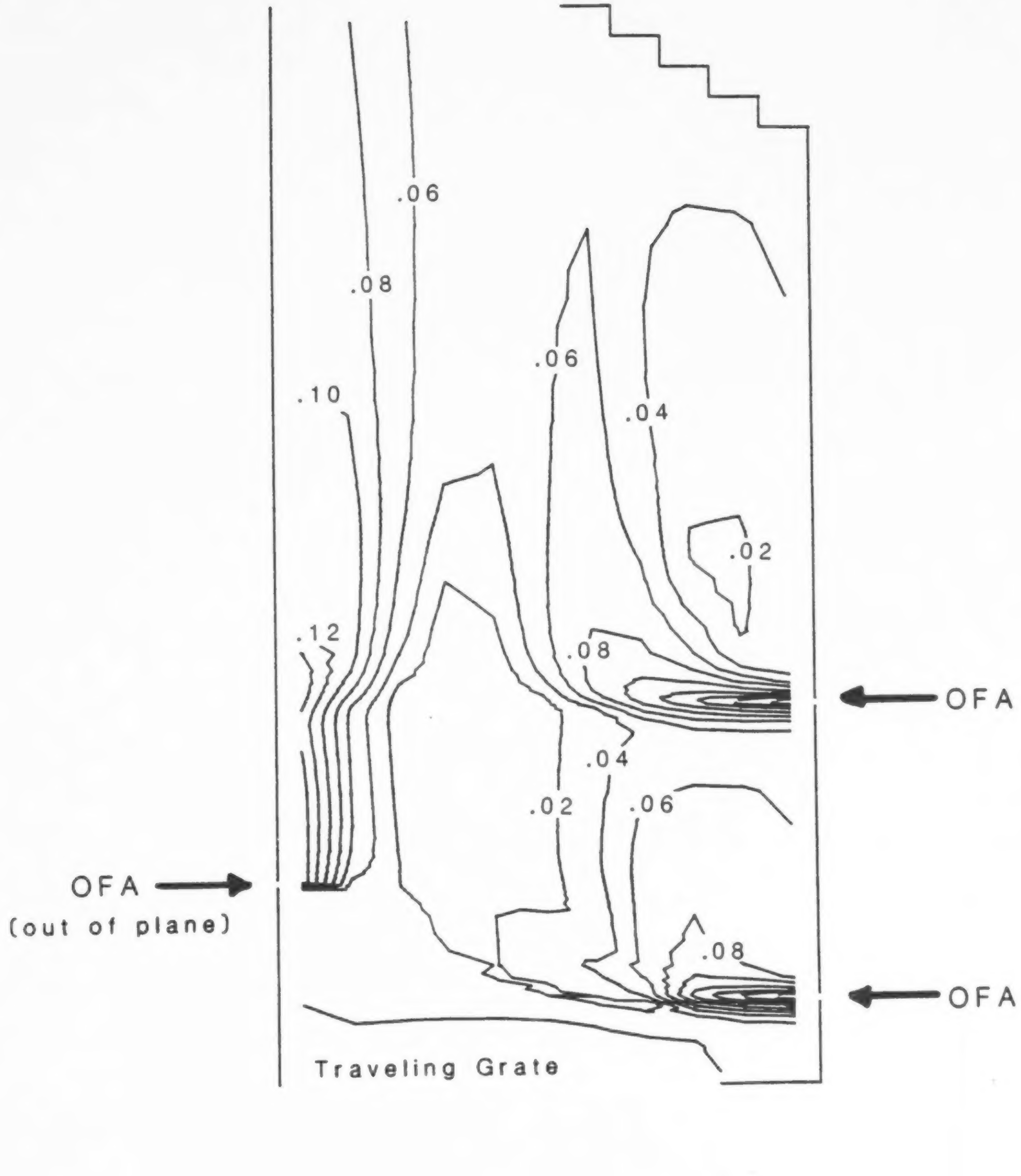

.06
.08
.10
.12
.06
.04
.02
.08
.04
.02
.06
.08
OFA
OFA
OFA
(out of plane)
Traveling Grate

Figure 6. Predicted Oxygen Mass Concentration Profiles for an RDF-Fired Boiler with Multiple Levels of Overfire Air Injection

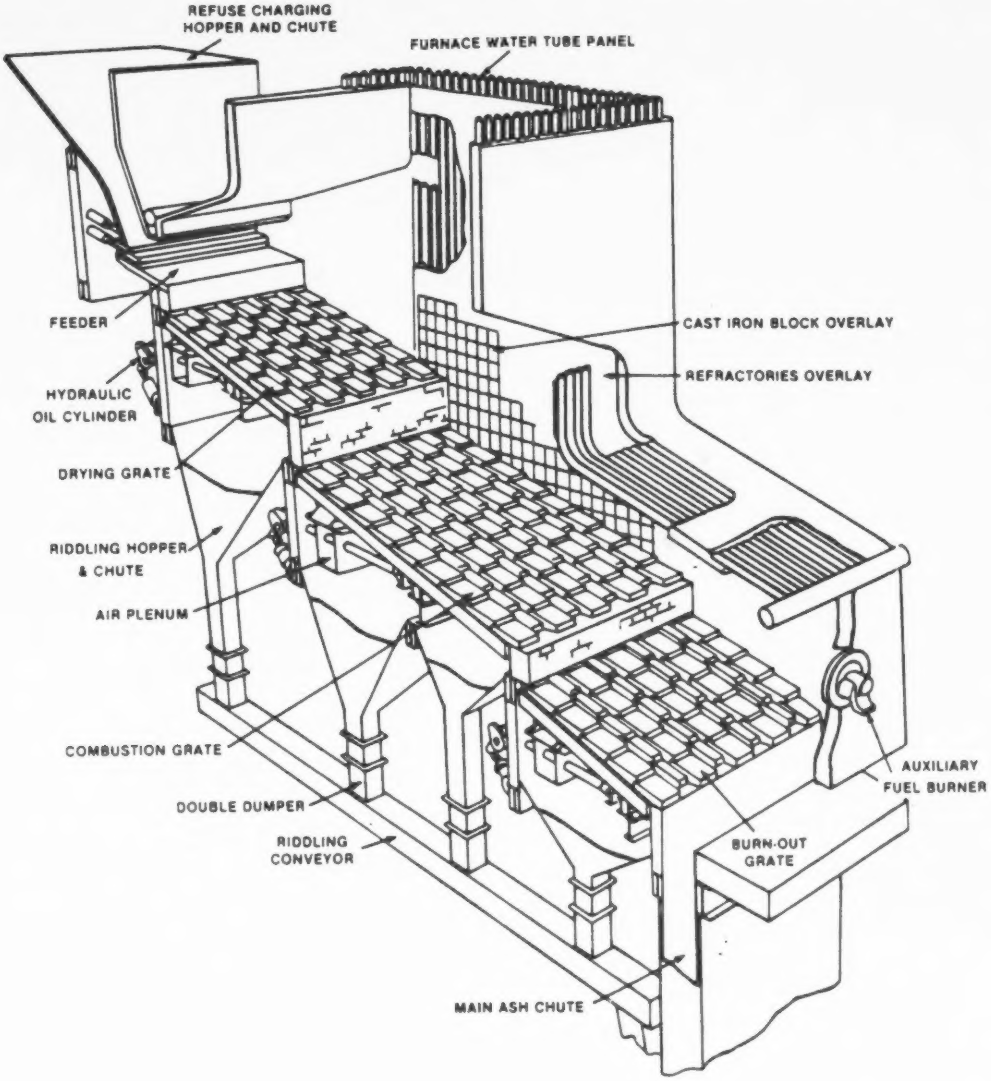

REFUSE CHARGING HOPPER AND CHUTE
FURNACE WATER TUBE PANEL
FEEDER
CAST IRON BLOCK OVERLAY
HYDRAULIC OIL CYLINDER
REFRACTORIES OVERLAY
DRYING GRATE
RIDDLING HOPPER & CHUTE
AIR PLENUM
COMBUSTION GRATE
AUXILIARY FUEL BURNER
DOUBLE DUMPER
RIDDLING CONVEYOR
BURN-OUT GRATE
MAIN ASH CHUTE

Figure 7a. Riley/Takuma Municipal Solid Waste Combustion System

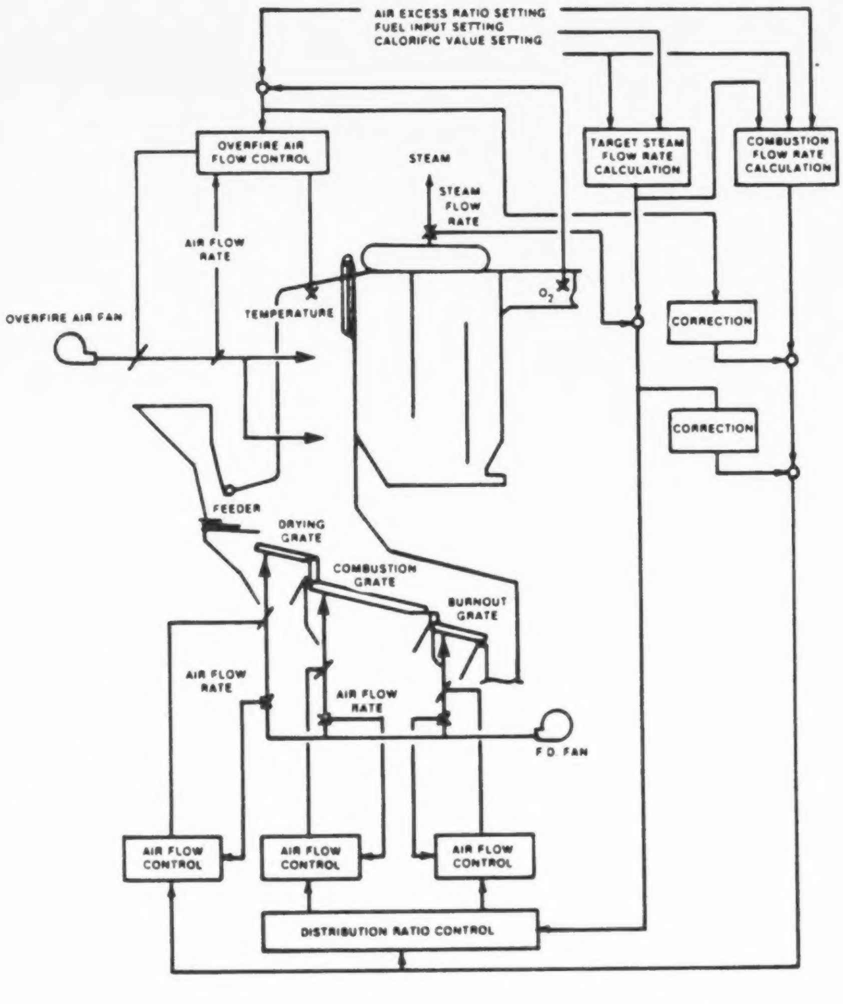

AIR EXCESS RATIO SETTING
FUEL INPUT SETTING
CALORIFIC VALUE SETTING
OVERFIRE AIR FLOW CONTROL
STEAM
STEAM FLOW RATE
TARGET STEAM FLOW RATE CALCULATION
COMBUSTION FLOW RATE CALCULATION
AIR FLOW RATE
O_2
TEMPERATURE
OVERFIRE AIR FAN
CORRECTION
CORRECTION
FEEDER
DRYING GRATE
COMBUSTION GRATE
BURNOUT GRATE
AIR FLOW RATE
AIR FLOW RATE
F.D. FAN
AIR FLOW CONTROL
AIR FLOW CONTROL
AIR FLOW CONTROL
DISTRIBUTION RATIO CONTROL

Figure 7b. Schematic Diagram of Riley/Takuma Combustion Air and Low Oxygen Control System

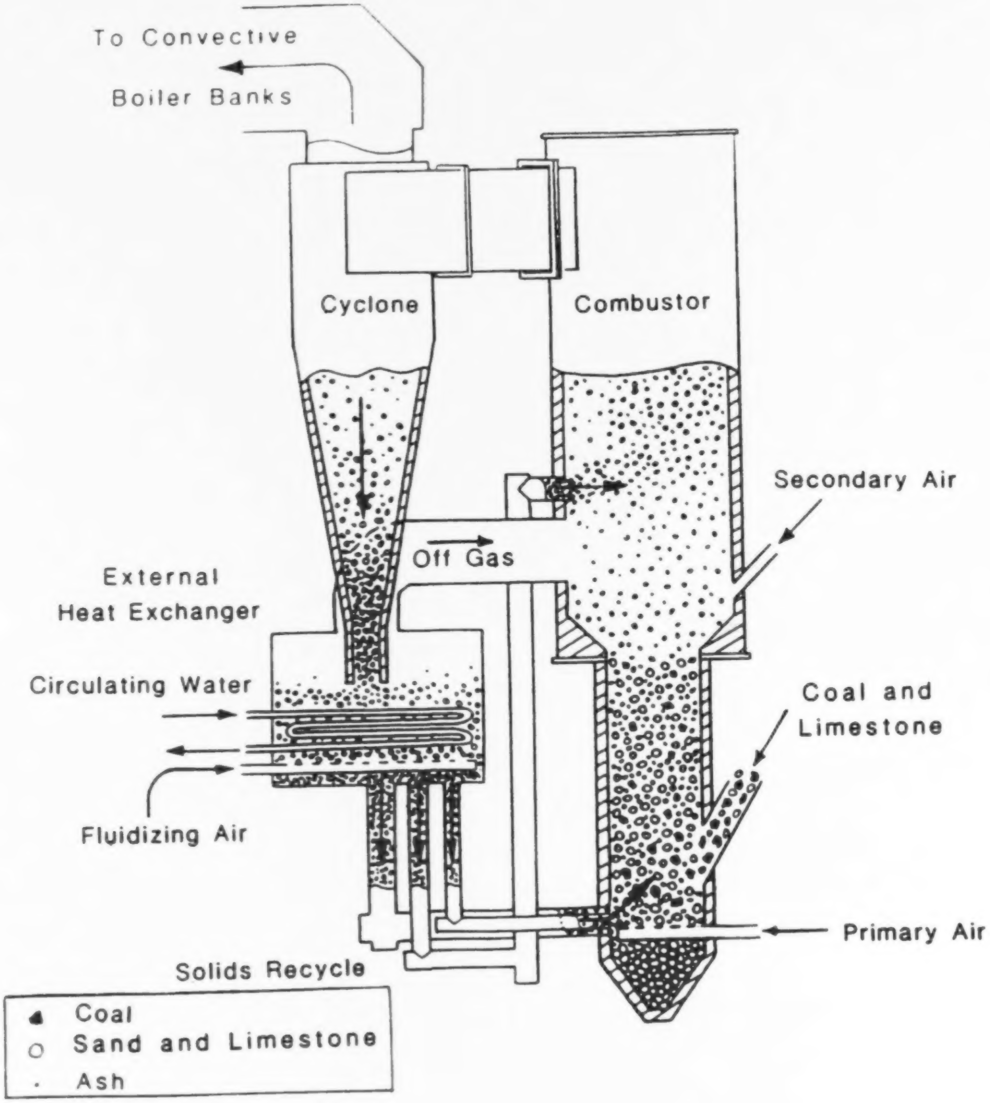

To Convective
Boiler Banks
Cyclone
Combustor
Secondary Air
Off Gas
External
Heat Exchanger
Circulating Water
Fluidizing Air
Coal and
Limestone
Primary Air
Solids Recycle
● Coal
○ Sand and Limestone
· Ash

Figure 8. Multi-Solid Fluidized Bed Combustion Process

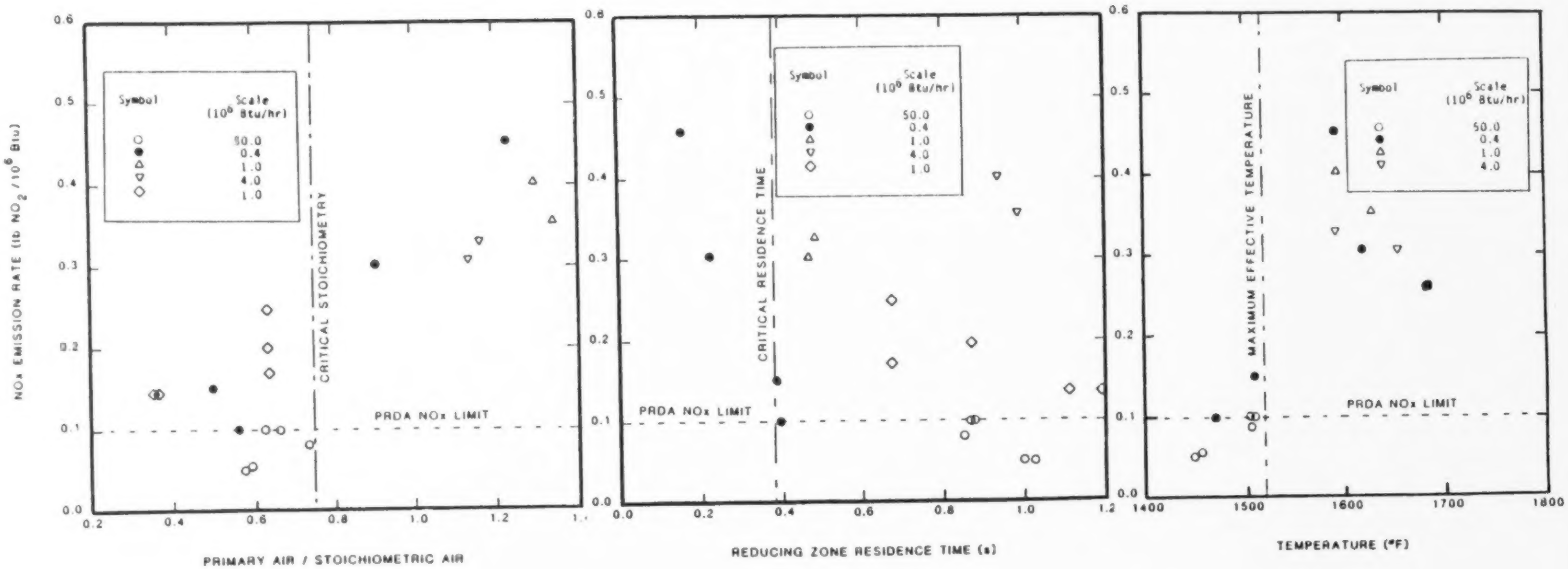


Figure 9. NOx Emissions Data from MSFBC Systems

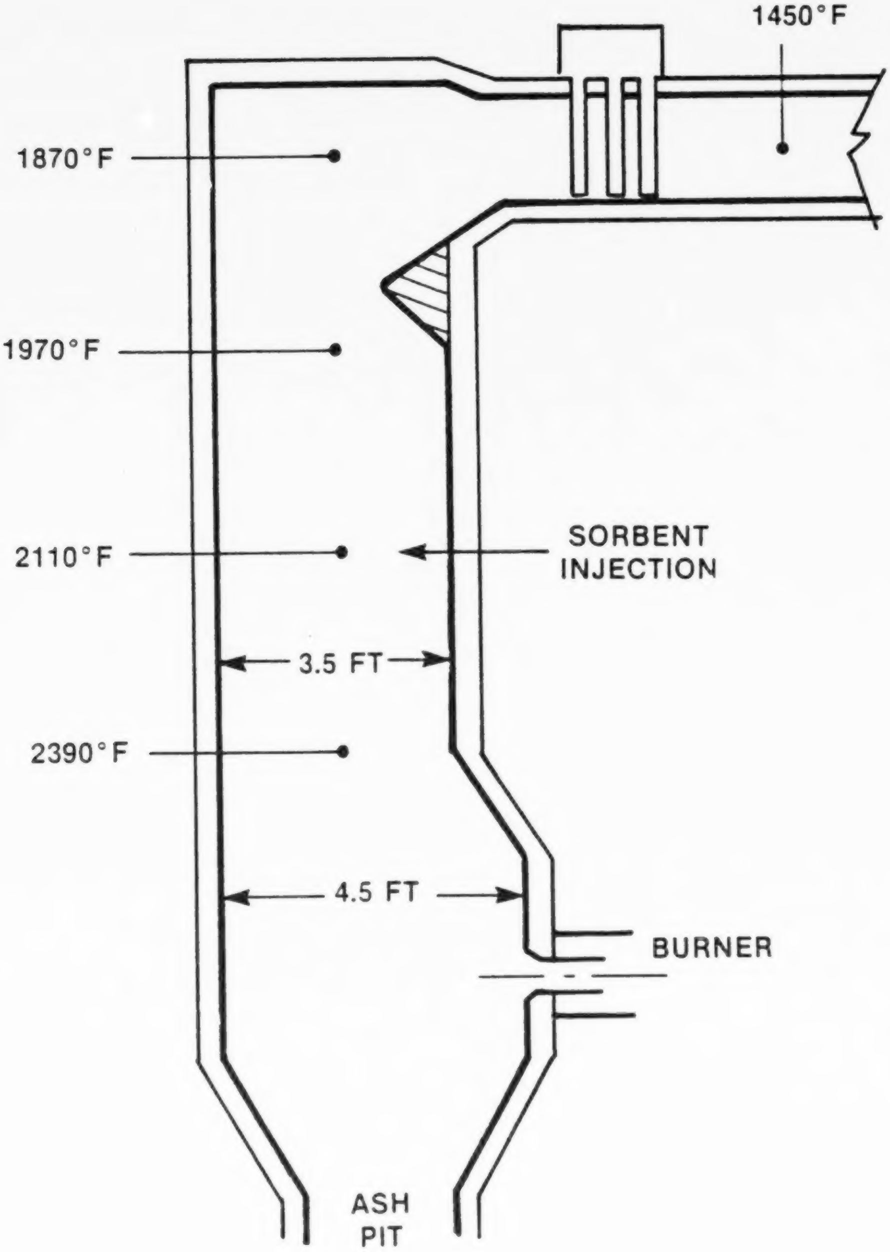

1450°F
1870°F
1970°F
2110°F
SORBENT INJECTION
3.5 FT
2390°F
4.5 FT
BURNER
ASH PIT

Figure 10. 3 x 10^6 Btu/hr. Pilot-Scale Combustion Facility

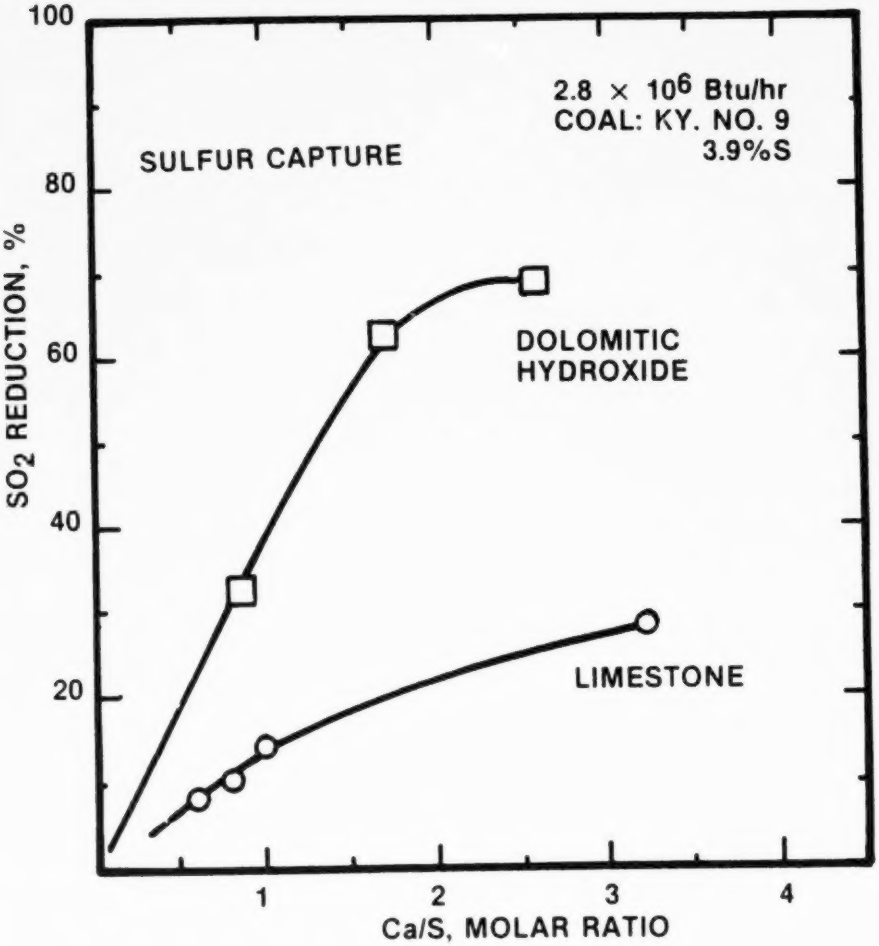


Figure 11. Comparison of Sorbents Tested in the Riley Research Pilot-Scale Furnace. Sorbent Injection at 2100°F, 2.8 x 10^6 Btu/hr, Kentucky No. 9 Coal

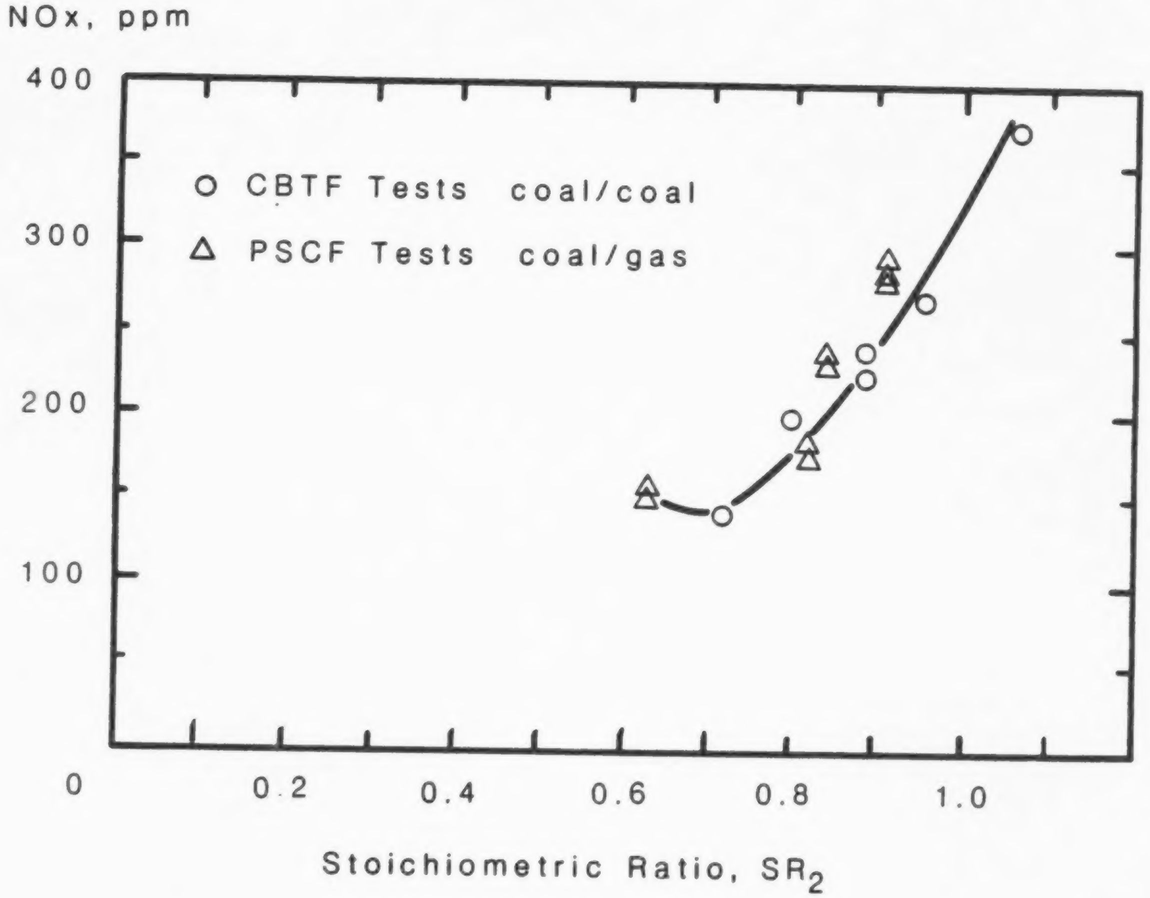


Figure 12. Reburning Test Results -
100×10^6 Btu/hr CBTF and 3×10^6 Btu/hr PSCF

INDUSTRIAL AND UTILITY BOILER LOW NO_x CONTROL UPDATE

by

JOEL VATSKY
Director, Combustion and Environmental Systems

and

EDMUND S. SCHINDLER
Supervisor, Emission Control Engineering

Foster Wheeler Energy Corporation
Livingston, New Jersey

ABSTRACT

NO_x control has been passing through various phases as the regulatory and commercial climate have changed since the early 1970's. During the decade of the '70's emphasis by boiler manufacturers was on developing and field demonstrating NO_x controls to meet the New Source Performance Standards of 1971 and 1979. More recently, with the reduced need for new utility generating capacity, emphasis has shifted to retrofittable technologies to meet pending acid rain control legislation. This paper discusses field experience with Foster Wheeler's low NO_x coal burner which is an inherently retrofittable design, on industrial and utility boilers. New concepts and their potential uses are also outlined.

INTRODUCTION

Foster Wheeler Energy Corporation, the boiler manufacturing division of Foster Wheeler Corporation, has been developing low NO_x control systems for about twenty years. Boilers sold after 1971 to meet the NSPS NO_x regulation (0.7 lb/million Btu) initially utilized overfire air ports for NO_x control. From the mid-1970's on FWEC used a first, and then second, generation low NO_x burner. Both designs were developed to be compatible with furnaces designed for pre-NSPS turbulent burners. To date well over 1000 first generation Controlled Flow burners are in operation, as are several hundred second generation Controlled Flow/Split flame low NO_x burners.

(0257t)

In addition to new industrial and utility steam generators considerable experience has been gained on retrofitted units of both types. All of these units were originally designed for, and most had operated with, turbulent pre-NSPS burners. NO_x reductions of 50-60% are achieved without any supplementary controls, such as overfire air.

However overfire air can be used to provide additional NO_x reduction when needed. To this end FWEC has investigated an advanced overfire air technique which, under test conditions, has demonstrated NO_x levels of about 0.2 lb/million Btu on two utility units. Lower levels have been achieved on a new 80 million Btu/hr test facility by combining the CF/SF burner with the advanced overfire air system. It should be noted that the NO_x levels will vary with fuel constituents, such as N_2, heating value and volatile content.

More advanced NO_x controls are also under consideration for development. These include a fuel-staged burner, which is a patented FW concept where the fuel is staged within the burner's throat to produce fuel rich and fuel lean zones. Also, a reburning system utilizing a coal-based synthetic gas in conjunction with a standard low NO_x combustion system has been proposed to DOE for consideration in a future clean coal demonstration.

NO_x: CAUSES AND CONTROL MEASURES

NO_x emissions from fossil fuel fired steam generators consist of approximately 95% nitric oxide (NO) and about 5% nitrogen dioxide (NO_2). In the atmosphere, NO reacts with hydrocarbons and sunlight to form ozone, a key constituent of photochemical smog. NO will also oxidize to NO_2 and then combine with available atmospheric moisture to form dilute nitric acid, HNO_3, one of the acid rain constituents. Thus, NO_x is a major ingredient and precursor to photochemical smog and acid rain, depending on the local conditions.

The NO_x level from a given fuel is a combination of two sources:

(1) Thermal NO_x produced by high temperature fixation atmospheric nitrogen (N_2) and oxygen (O_2). This effect is exponential with temperature with negligible NO_x emission below a peak flame temperature of about 2800°F.

(2) Fuel NO_x is generated from the chemically-based atomic nitrogen in the fuel's hydrocarbon molecules. The level of fuel-NO_x emission is a function of fuel type and varies from zero for natural gas (which has no bound nitrogen) to 60-80% of the total emission for coal.

Thermal NO_x is controlled by decreasing the peak flame temperature and fuel NO_x is reduced by controlling the distribution of air and fuel within the burner. When the initial combustion phase occurs in a reducing atmosphere environment, the nitrogen released from the fuel competes with carbon and hydrogen for an insufficient amount of oxygen. The reaction kinetics are such that nitrogen loses the competition for oxygen thereby reducing the quantity of NO formed (as compared to the oxidizing condition). Nitrogen released from the fuel will interact to form harmless N_2 molecules.

Subsequent to the passage of the 1971 Clean Air Act, the first generation NO_x control techniques were incorporated in new boiler designs. Although Foster Wheeler incorporated overfire air into the early New Source Performance Standards (NSPS) boilers, low NO_x burner development concentrated on utilizing internal flame staging techniques to minimize the design and cost impact NO_x controls would have on the boiler configuration. By 1976, FWEC was using the first generation Controlled Flow low NO_x burner which reduced NO_x by up to 35% without overfire air and, when used in conjunction with overfire air, reduced

NO_x by up to 60% in the field.

In 1979, FWEC began using the second generation internally staged low NO_x burner: the Controlled Flow/Split-flame design. Typically, this burner has achieved 50-60% NO_x reduction in field operation, as compared to pre-NSPS turbulent burners, and up to 75% reduction in combination with overfire air.

During this time interval, other researchers were investigating the potential of NO_x control using an externally staged Distributed Mixing Burner.

Figure 1 schematically compares a boiler equipped with overfire air for NO_x control with one equipped with tertiary air ports. Although the latter can reduce NO_x further, its complexity and resulting high cost are apparent. Figure 2 schematically compares the flame conditions produced by delayed-mixing low NO_x burners with those of FWEC's internally staged burner.

Although the NO_x reduction capabilities of these techniques are similar, as shown in Figure 3, the practical consequences of each are significantly different and are summarized as follows:

Overfire Air:	When used is sufficient quantity to yield large NO_x reductions major slagging and high unburned carbon levels can result.
Tertiary Air Ports:	These produce satisfactory NO_x reductions but at very high capital cost. This cannot be retrofitted to most pre-NSPS steam generators without severe structural and pressure part modification.
Delayed Mixing Burners:	These produce long, lazy flames which can impinge on tube surfaces in pre-NSPS boilers not designed to accommodate this type of burner. Flame length limits burner capacity since furnace height is fixed.
Internally Staged Burner:	This has a flame envelope nearly identical to that of pre-NSPS turbulent burners. It is not limited in capacity and can generally be easily retrofitted.

Foster Wheeler, having investigated the advantages and disadvantages of each method, chose the internally-staged burner concept for development. The primary reasons are:

(1) No changes to furnace design criteria would be necessary to accommodate low NO_x conditions, as compared to boilers designed for turbulent burners.

(2) The internally staged design controls both thermal and fuel NO_x by reducing peak flame temperature and by producing substoichiometric conditions in the throat region of the flame without resorting to external staging. However, overfire air can be used to obtain additional NO_x reduction when needed.

(3) The same number of burners could be used.

(4) No special requirements are placed on the pulverizer or on flow controls.

(5) The same burner design can be used for both new and retrofit applications.

The Controlled Flow/Split-flame burner was placed in successful utility service by late 1979 when it was retrofitted to the 360 MW San Juan Unit No. 1 of Public Service Company of New Mexico. Since then, it has been the standard offering for both new and retrofit applications.

LOW NO_x SYSTEM DESCRIPTION

The low NO_x system consists of two components: low NO_x burners and boundary air ports. Both have been in field service since the mid 1970's.

The first generation Controlled Flow low NO_x burner, shown schematically in Figure 4 is a dual register design with the registers arranged in series. The inner register controls the swirl and stoichiometry around the coal injector while the outer register affects the flame envelope's shape.

Surrounding the register assembly is a perforated plate air hood which improves the circumferential distribution of secondary air entering the outer register. By measuring the pressure drop across each burner's perforated plate, an index of the secondary air flow can be obtained. This index aids in balancing burner stoichiometries to minimize excess air requirements. Therefore, since secondary air distribution within the windbox is optimized, the common windbox can be retained and there is no need to modulate burner air flow controls.

The coal injector consists of a tangential scroll inlet, annular fuel barrel and annular nozzle with axially movable inner tip. Adjusting the inner tip will vary the primary air/coal mixture's velocity so that it can be optimized with respect to the secondary air.

The Controlled Flow burner has been supplanted by Controlled Flow/Split-flame low NO_x burner since 1979. However the former design is still offered commercially where improved combustion, air flow control and flame shaping (as compared to pre-NSPS burners) are required.

The CF/SF burner, shown in Figure 5, is identical to the CF burner with the exception of the split-flame coal nozzle. The coal is collected into four concentrated streams which yield substoichiometric flames in the near-throat region while the burner operates at normal excess air levels. The split-flame coal nozzle also includes the axially-adjustable inner sleeve tip. Control of the primary air/coal distribution and velocity is an integral part of achieving low NO_x levels with acceptable flame conditions.

Advantages of the CF/SF low NO_x burner design which enhance its attractiveness for use on retrofitted boilers, as well as new units, include:

(1) Does not rely on long, narrow delayed mixing flame to achieve low NO_x.

(2) Fully compatible with existing burner management, flame scanning and ignition systems.

(3) "Plug-in" retrofittability: No pressure part or structural modifications are required for burner installation.

(4) Same burner pressure drop as historically used with turbulent burners (2-4" W.C.).

(5) Independent control of secondary air flow and swirl at each burner thus allowing air/fuel ratio to be optimized at each burner without modifying swirl; and without modulating secondary air flows.

In addition to the low NO_x burners, a set of boundary air ports, requiring a total of four openings in the tubewalls for opposed fired units is offered. Their location is schematically shown in Figure 6. The ports inject windbox air along the sidewalls in order to produce a high excess O_2 concentration which will not vary significantly as pulverizers are taken in and out of service over the boiler's upper load range. In combination with the burner's ability to adjust secondary air flow distribution both vertically and horizontally within the windbox, the boundary air system is intended to maximize the overall flexibility to control oxygen distribution during combustion.

EMISSIONS DATA

A substantial body of operational and emissions data for industrial and utility steam generators, equipped with the CF/SF burner, has been obtained over the past ten years. Some of the more interesting results are those obtained on steam generators designed for use with turbulent burners and subsequently retrofitted with the CF/SF low NO_x burner.

Figure 7 summarizes NO_x emission data from two industrial boilers and two test facilities. FWEC's initial low NO_x burner development work was performed on a 125,000 lb/hr 4-burner industrial unit originally equipped with FWEC's turbulent intervane burners. NO_x was reduced 60% with no adverse effects on the unit's steam generation or efficiency. Similarly, in 1984 a retrofit was made to a 110,000 lb/hr 4-burner steam generator at a Du Pont chemical plant in Martinsville, Virginia; primarily for the purpose of demonstrating SO_2 control via sorbent injection. The demonstration was funded by Consolidation Coal Company; FWEC's part being the supply of low NO_x burners with integral limestone injectors. NO_x was reduced 50% without any measurable change in Furnace Exit Gas Temperature as determined by FWEC's boiler performance program and in-situ HVT measurements performed by Conoco.

Figure 7 also contains summary data from a single burner 50 million Btu/hr test furnace, rented by FWEC, where burner optimization and fuel characterization was performed after the initial development was completed. Some initial results from FW's new 80 million Btu/hr Combustion and Environmental Test Facility, equipped with two 40 million Btu/hr burners are also shown. Tests were performed with both intervane and low NO_x burners: NO_x was reduced to below 0.4 lb/million Btu and to below 0.2 with overfire air ports open.

FWEC has also made several retrofits to utility steam generators; only one of which was a contractual necessity. Figure 8 summarizes NO_x emission results from three utility units with the data from the 110,000 lb/hr Du Pont Martinsville unit included for comparison.

The first unit shown is the 360 MW San Juan #1 of Public Service New Mexico. When sold, after the 1971 State of New Mexico NO_x regulations took effect, it had to meet the new regulation of 0.45 lb/million Btu (in contrast to the Federal EPA limit of 0.7). However, when started up in 1976 FWEC's low NO_x burner had not yet been developed. Consequently, the unit was equipped with turbulent burners with NO_x control via overfire air only. Emissions were about 0.95 lb/million Btu with OFA ports closed (and less than 0.7 with OFA ports open). The State of New Mexico Regulation (0.45) was not attainable.

San Juan #1 was retrofitted with Controlled Flow/Split-flame low NO_x burners in 1979 with NO_x reduced to about 0.4 lb/million Btu, without overfire air. Subsequent to this success, which was a true retrofit, the CF/SF burner was installed on several units which were in the construction phase, in keeping with FWEC's policy of providing our newest technologies where practical. One of these units, all of which had been designed for turbulent burners, is a 525 MW steam generator. Data for this unit, with and without overfire air, is also shown on

Figure 8. There are several other steam generators, retrofitted in the early 1980's while being constructed, ranging from 250 MW to 700 MW which show similar results. Most do not have overfire air ports and those which do have them do not need them to meet the relevant NSPS requirements.

The most recent retrofit is the 650 MW unit also shown on Figure 8. This is the Pleasants Station Unit #2 of Allegheny Power Corp. The following section discusses this unit in more detail.

PLEASANTS UNIT #2 LOW NO_x BURNER RETROFIT

Allegheny Power System's Pleasants Power Station has two identical Foster Wheeler supercritical once-through steam generators (Figure 9). These 5,035,000 lb/hr single reheat units supply steam to 626 MW (net) Allis-Chalmers turbine-generators and were designed to meet the requirements of the 1971 new source performance standards, which limit NO_x emissions to 0.7 lb/million Btu. They are equipped with wet scrubbers to control sulphur emissions.

The steam generators were equipped with overfire air ports as the only means of NO_x control. NO_x emissions in Unit Nos. 1 and 2 averaged between 0.6 and 0.7 lb/million Btu after start-up in 1978 and 1980, respectively. Unit No. 2 has less margin than Unit No. 1, however, and as a result, Unit No. 2 experienced periodic derates to avoid exceeding the regulatory limit. It was determined that the best method of eliminating the derates due to NO_x limitations was to install low NO_x burners.

Foster Wheeler's Controlled Flow/Split-flame low NO_x burner was installed in Unit No. 2 during a four week outage in 1986. In addition to eliminating NO_x derates, it was anticipated that the new burners could help boiler performance in the following areas:

(1) Induced draft fan limitations - The ID fans were designed with insufficient capacity margins to accommodate some fuel/moisture/load combinations. The low NO_x burners operate with less excess air, thus providing greater capacity margin.

(2) Furnace sidewall corrosion - The low Nox burners with lower boundary air ports admit more combustion air in the furnace zone by eliminating overfire air thus providing more oxidizing air for the sidewalls.

(3) Air register maintenance - Reduced maintenance costs would result by not having to maintain air port and burner registers.

(4) Boiler efficiency - Improved boiler efficiency would result due to reduced dry gas loss resulting from low excess air operations.

The steam generator has 24 burners with 12 on each of the front and rear walls. Each of the six rows of four burners are supplied by a ball mill pulverizer. The unit has eight overfire air ports which were used to admit air for NO_x control.

The original intervane burners were removed so that the new low NO_x burners could be installed. The intervane burner is a basic design with one air register and the coal nozzle consisting of an inner and an outer barrel. Coal enters the annulus between the barrels tangentially through the scroll. The primary air/coal stream mixes with the secondary air in a highly turbulent manner.

The low NO_x system installed at Pleasants includes the low NO_x burners and boundary air ports which were installed in the four corners of the furnace above position: NO_x is reduced a total of 67% from the completely uncontrolled condition.

Table I summarizes typical flue gas measurements for the two burners. Unburned carbon loss, being a key measure of efficiency, was measured after the low NO_x burners were optimized. As shown on Table I, the unburned carbon level in the flyash was below 2.5% (measured in a loss on ignition test). For the coals used, this translates to less than 0.35% as efficiency loss, which is within the normal range for pulverized bituminous coal-fired boilers.

The fuel in use at the station is a middle Kittanning high volatile bituminous coal. Table II compares the contract boiler performance coal with the fuel used during the 1981 start-up and shakedown and the fuel currently being burned.

The most significant differences between the current fuel's characteristics and those of the earlier fuel are:

- Increase in fixed carbon to volatile matter ratio of about 10% (1.31 to 1.45)
- Increased fuel nitrogen content of about 40% (0.9 to 1.3)

Both of these changes would tend to increase NO_x emissions, all other factors being equal.

Operational Results

In parallel with achieving low NO_x levels is the importance of not degrading steam generator performance and efficiency, nor of creating operational difficulties for the station's personnel.

Areas of particular concern are discussed below, along with actual observations:

(1) Burner Pressure Drop: Any increase in burner resistance, either on the primary or secondary air side, would result in higher power consumption.

- Primary air fan power consumption is in the same range as with the original coal injectors, indicating no significant change to nozzle flow resistance.
- Windbox-to-furnace pressure drop is the same as before: at full load with all burners in service and overfire air ports closed P is about 3.0 - 3.5" W.C. With OFA open, it is approximately 1.5" W.C., both at normal excess air of 20% (3.6% O_2).

(2) Furnace Exit Gas Temperature: Some types of low NO_x systems rely on long, delayed mixing flames which have the potential for increasing FEGT. If this were to occur on the Pleasants unit, the resulting increase heat head across the convection pass would cause:

- Higher spray flows to control superheater temperature
- Shifts in reheat control damper positions (the unit uses a parallel pass convection arrangement for reheat control) to prevent high reheat temperatures. Higher air heater inlet temperature could also result.

None of these potential adverse effects have been noted over the past 14 months of low NO_x burner operation. Consequently, the absorption patterns which can be observed and measured with normal steam generator performance techniques show no change due to the low NO_x burners.

3. Slagging and Fouling: Since the coal can be classified as having a medium to high slagging potential, additional ash deposition would be of concern, particularly during low NO_x firing.

   o Furnace Slagging: With the original burners, the walls were covered with a thin, light coating of ash. However, very large "eyebrows," up to 6' in length, would form over the burner throat openings. In many cases, the flames would be burning through a "tube" of slag. The burner throat refractory modifications made during low NO_x burner installation have resulted in the eyebrows being reduced in size to the point where they no longer affect the flame or cause other adverse impacts.

   Ash coverage on the walls is essentially the same as before. The visual observations made are somewhat subjective since there is no adequate means of directly quantifying ash extent and quality. However, the thermal measurements discussed in (2) above also confirm that there has been no increase in furnace deposition. A significant increase in furnace wall coverage would reduce absorption in this region thereby causing high FEGT with previously noted adverse consequences.

   - Fouling: Visual observations and evaluation of the thermal measurements indicate no increase in superheater fouling or convention pass deposition. Again, this implies that extended flames and upper furnace combustion have not occurred.

   Thus, after over one year of operation, there have been no unsatisfactory or adverse side-effects resulting from the low NO_x burner retrofit.

FIELD DATA COMPARISONS

NO_x emissions from coal combustion consist of two components: thermal fixation of atmospheric nitrogen and conversion of fuel-bound fixed nitrogen to NO. Furnace thermal conditions will affect thermal NO_x generation while burner type will affect both thermal and fuel No. Foster Wheeler has determined the characteristic relationships between NO_x emissions, furnace configuration and combustion intensity as represented by the Burner Zone Liberation Rate (BZLR is a measure of the heat input to the burner zone, the higher this value the higher the furnace temperature).

Figure 13 is a summary of NO_x emissions from turbulent and low NO_x burners. The upper two curves represent the variation of NO_x with BZLR for single wall and opposed fired units equipped with intervane burners. The bottom curve is for the CF/SF low NO_x burner. Data from industrial and utility units and FW's test facility (CETF) are shown. There is very good correlation between data points and predictive curves.

A parameter of paramount interest when evaluating the performance of a combustion system, is the unburned carbon loss. This measure of combustion efficiency is dependent on burner design, excess air, fuel particle fineness and coal type. FWEC continually evaluates the performance of its combustion systems and has not yet observed any generic change in unburned carbon levels due to its low NO_x burners.

Figure 14 compares unburned carbon loss to NO_x level for several steam generators. Three different conditions are represented:

- o Pre-NSPS units equipped with intervane burners
- o NSPS units equipped with intervane burners and overfire air ports for NO_x control. These units are designed to meet the 1971 NSPS level of 0.7 lb/million Btu.
- o NSPS units equipped with CF/SF low NO_x burners.

The range of unburned carbon loss for each condition is about the same: there is no indication of higher unburned carbon level due to FW's low NO_x system.

ADVANCED NO_x CONTROLS

Foster Wheeler has been investigating advanced NO_x control measures for new unit and retrofit use. Some technologies which can be relatively easily incorporated into a new steam generator cannot be economically retrofitted to pre-NSPS units. The following summarized three techniques for achieving lower NO_x levels that are under investigation by FWEC.

Advanced Overfire Air

Conventional overfire air systems, as presented above, utilize approximately 20% of the total combustion air flow with ports located above the top burner level. Under these design conditions NO_x reductions of about 30 - 35% are achievable. Although greater reductions are obtainable by using more overfire air (lowering the burner stoichiometry) the potential adverse side-effects of such large OFA quantities generally preclude their use.

However, it has been determined that improved NO_x reduction can be attained by increasing the distance between the overfire air level and the top burner level, thereby increasing the residence time in the stoichiometric flame for reactions which reduce NO to N_2 to occur. This concept was field demonstrated in the early 1980's on two utility steam generators which had been retrofitted with CF/SF burners during construction. Both units were designed for future lignite firing and, as such, were equipped with an extra level of burners.

The arrangement of one of these units is schematically shown in Figure 14. The units fired much higher quality coal when initially started up. When operating with the overfire air ports closed and the top burner level out of service, at full load, the top burners act as conventional overfire air ports. When the top burner's registers are closed the overfire air ports are used the residence time is significantly increased over that of the conventional overfire arrangement.

More recently, FW has started up an 80 million Btu/hr Combustion and Environmental Test Facility*, shown schematically in Figure 15. As can be seen, the CETF furnace in equipped with overfire air ports located well above the top burner level.

Figure 16 summarizes the effect of increased OFA residence time on the two utility boiler (data from 1981 and 1982) and the CETF (data from 1986). The results are consistent in that the increased residence time yields a NO_x reduction nearly double that of the standard ports: 50% vs. - 30%.

Although these are very encouraging results additional investigation and testing will be done to fully confirm the effects and optimize it for a wide range of coals.

Reburning

Reburning is a means of decreasing NO_x emissions by injecting a reducing agent, such as natural gas, above the burner zone end in a low oxygen atmosphere. NO produced in the burner zone is reduced to N_2 on the hydrocarbon fractions of the injected gas. Although reburning with natural gas can reduce NO_x emissions by about 50%, up to 20% of the steam generator's heat input must be from gas.

The complete reburning scheme includes overfire air ports located above the reburning fuel injectors. Consequently, a substantial part of the steam generator's heat input is now released near the entrance to the convection pass. This may severely limit the applicability of reburning on pre-NSPS units, unless major modifications are made to the convection pass.

Foster Wheeler's approach is to use low NO_x burners with overfire air, where necessary, on both new and retrofit applications. Reburning may be used, where especially low emission levels are needed, but only as a "topping cycle" after maximum benefit has been obtained by combining low NO_x burners and overfire air.

* The CETF's operational characteristics and recent test results are discussed in a companion paper "Low NO_x Developments on an Integrated Combustion and Environmental Test Facility."

Since natural gas is a premium fuel and may be in short supply in the future, although there is a current "glut", there could be substantial risk to utilities by relying on this fuel for emission control and as a partial substitute for coal. In the long term a more reliable means of reburning, assuming it proves to be commercially viable in utility application, may be with coal as the reburning fuel.

Pulverized coal is difficult to utilize directly for reburning. Consequently, FW is investigating the use of a commercially proven two-stage gas producer to generate a synthetic lower Btu gas for use as the reburning fuel. A by product of this system is a heavy oil which can be stored and used for start-up. Figure 17 schematically illustrates the system configuration on a coal fired utility steam generator.

Since the NO_x level emitted by an emission control system will vary with coal quality a topping system, such as reburning, may provide the added margin and flexibility to maintain the NO_x level invarient with varying fuel conditions.

Fuel Staging Low NO_x Burner

In keeping with FWEC's emphasis on the low NO_x burner as the primary NO_x control device, investigations have been continuing on the development of a fuel staged pulverized coal burner, depicted in Figure 18. This design, based on several patents, combines the wide turndown ability of FWEC's low load burner with low NO_x concepts of fuel staging.

A central substoichiometric flame, generated from the low load coal nozzle, provides incomplete products of combustion which enter the main flame from the high load nozzle. NO generated in the latter is reduced to N_2 on the hydrocarbon particles and gases from the low load nozzle.

The system design is such that the low load nozzle is always producing a flame, is that the total burner can have a turn-down of up to 10:1.

the ash hopper slope as shown in Figure 6. These air ports inject windbox air along the sidewalls in order to produce high O_2 levels between the wing burners and sidewalls, and is intended to reduce furnace sidewall corrosion that occurs when a local reducing atmosphere exists in this region.

An important feature of the low NO_x system is the ability to reduce overall excess O_2 levels. This can be achieved because of the ability to balance burners in the windbox and by closing the overfire air ports. In order to be able to determine this minimum excess O_2 level, carbon monoxide (CO) monitors were added to the unit. It was felt that the O_2 could be lowered to a point before CO appeared in unacceptable levels, providing that no other adverse conditions existed (e.g., severe slagging, sidewall wastage).

The low NO_x burner system was installed during a four-week outage that occurred in February, 1986. The burners were designed so that no pressure part modifications were necessary in the burner throat area. The existing burners, air registers, and scrolls were removed. The new air register assemblies, inner and outer barrels were installed and the existing scrolls were reused. Modifications to the outer windbox wall were completed to accommodate the new manual actuators, to reposition the main register drive motors. A modification was done to the burner refractory that involved removal of some refractory, leaving a leaner profile. This was intended to reduce the chances of slag accumulations, or "eyebrows." During this outage, the overfire air ports were repaired and left operable in case overfire air was needed to meet the lower NO_x performance guarantee.

Emission Test Results

The Pleasants No. 2 unit was originally brought into commercial operation in 1981. Installed within the common windbox, as shown in Figure 9, the overfire air dampers remove secondary air from the burners in order to decrease burner stoichiometry. This design was set to produce an NO_x margin of about 10% below the guarantee level, based on the contract performance coal. However, NO_x emissions will vary with coal constituents, load, excess air and the number of pulverizers or burners out of service. With this configuration, burner register position will also affect NO_x, primarily by changing windbox pressure which modifies the amount of overfire air flow.

Figure 10 compares the NO_x emission results as a function of excess O_2 for the turbulent intervane burners with and without overfire air. This data, taken during and shortly after the initial start-up, was typical of subsequent operation. Although there were periodic incidents requiring unit load to be reduced in order to prevent NO_x exceeding the regulatory limit as indicated by the stack monitor, checks by both FWEC and independent test contractors confirmed the lower curve of Figure 10.

After installation of the low Nox burners and boundary air ports, during a four week January/February, 1986 outage, start-up commenced in late February. Initial burner settings (inner and outer register and movable coal nozzle) were FWEC's standard start-up positions. After reaching full load with all burners in service and with overfire air and boundary air ports closed, it was found that the NO_x level was in compliance with the revised guarantee, 0.6 lb/10^6 Btu.

A two-week burner optimization and low NO_x monitoring period was undertaken. This produced the NO_x results summarized in Figure 11. With overfire air ports closed, NO_x was reduced to about 0.4 lb/10^6 Btu. With overfire air ports open, the NO_x level, during test conditions, was reduced to about 0.33 lb/10^6 Btu. Figure 12 summarizes and compares the performance of the intervane and low NO_x burners as a function of overfire air port damper

Figure 19 summarizes and compares the NO_x levels achievable by the various technologies discussed above; both commercially proven and predicted. There are several means of obtaining 80 - 90% total NO_x reduction from uncontrolled levels. Some of these techniques are complementary.

Combined NO_x/SO_x Control

Over the past ten years considerable effort has been expended by many researchers to develop a viable means of capturing SO_2 in-situ, i.e. inside the boiler. Foster Wheeler investigated one method, using pressure hydrated lime, injected to the upper furnace, 15 years ago. Testing was performed on an 80 MW steam generator where 50 - 60% SO_2 reduction was achieved at a Ca/S mol. ratio of 2-3.

More recently a method has been developed which utilizes pulverized limestone injected through the Controlled Flow/Split-flame low NO_x burner. Figure 20 shows the simple modification which does not detract from the low NO_x burner's capability. However, it should be noted that the injector size, location, angle and particle velocity are all critical parameters to achieve the desired SO_2 capture.

In 1984 this system was field demonstrated in a program funded by Conoco, on the 110,000 lb/hr industrial boiler discussed above. Figure 21 summarizes some pertinent SO_2 capture data by comparing FWEC's in-burner injection method with upper furnace injection on that unit. At a Ca/S mol. ratio of 2.5 the former method achieved 50% SO_2 reduction while the latter could only achieve 40%.

Of considerable significance from the operators viewpoint is the result that there were deleterious effects to steam temperature, furnace exit gas temperature or unit efficiency caused by either the low NO_x burners or the use of limestone for SO_2 control. However, it was necessary to increase the frequency of furnace and convection pass sootblowing to prevent the high solids loading from causing a reduction in heat transfer surface effectiveness.

The results of this field demonstration clearly showed the capability exists for combined NO_x/SO_x control of at least 50% each on industrial units. Since the CF/SF burner had independently been demonstrated at the utility scale, only confirmation of the in-burner limestone injection technique is needed.

SUMMARY

Foster Wheeler has obtained considerable experience with commercial low NO_x burners on both new steam generators and retrofitted units. Emission and boiler performance results are consistent in that NO_x is typically 50 - 60% lower than with pre-NSPS turbulent burners and there have been no indications of adverse effects on boiler performance or operation due to the low NO_x burners. Of particular significance have been the successful retrofits of industrial and utility units ranging in size from 110,000 lb/hr to 650 MW.

A Combustion and Environmental Test Facility has been started-up and test results correlated with field data. Figure 22 summarizes the NO_x reduction effects of the Controlled Flow/Split-flame low NO_x burner without overfire air and with an advanced overfire air system tested on two utility steam generators and the CETF.

Advanced combustion-based NO_x controls are under investigation and a relatively simple method of achieving simultaneous NO_x/SO_x reduction of 50% has been demonstrated on the industrial scale. Efforts are continuing to optimize and expand the applicability of these methodologies.

The work described in this paper was not funded by the U.S. Environmental Protection Agency and therefore the contenents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

TABLE I. EMISSION SUMMARY: PLEASANTS UNIT NO. 2

BURNER:	INTERVANE			LOW NOx		
	NO_x	CO	UC	NO_x	CO	UC
Units	lb/10^6	ppm	%			
OFA:Closed	0.95±0.05	40	2.5	0.41±0.02	40	2.5
OFA:Open	0.65±0.05	40-60	2.5	0.33	100	--

* No data was taken as this was a short-term test condition designed only to observe NO_x change.

+ Measured at economizer exit.

TABLE II. COAL ANALYSIS: PLEASANTS STATION

Constituent	Performance	1981	1986
FC/VM	1.36	1.31	1.45
N_2 (%)	1.0	0.9	1.3
FC (%)	43.6	47.9	50.4
VM (%)	32.1	36.6	34.7
Ash (%)	16.8	13.6	11.7
H_2O (%)	7.5	2.3	3.2
C (%)	62.3	69.4	70.0
H (%)	4.1	5.1	5.0
O (%)	5.1	6.4	5.4
S (%)	3.2	2.7	3.4
HHV (Btu/lb)	11,500	13,600	12,700

FURNACE STAGING TYPES

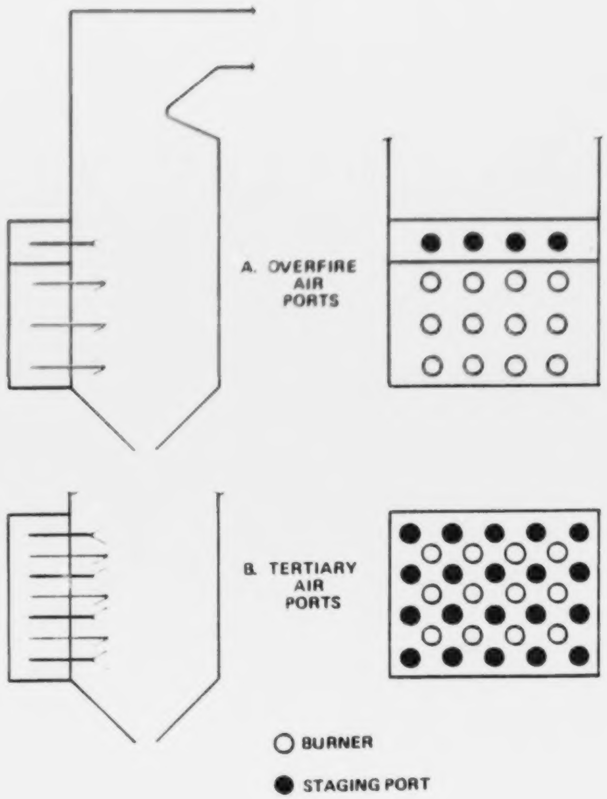

A. OVERFIRE AIR PORTS
B. TERTIARY AIR PORTS
○ BURNER
● STAGING PORT

FIGURE 1

LOW NOx BURNER TYPES

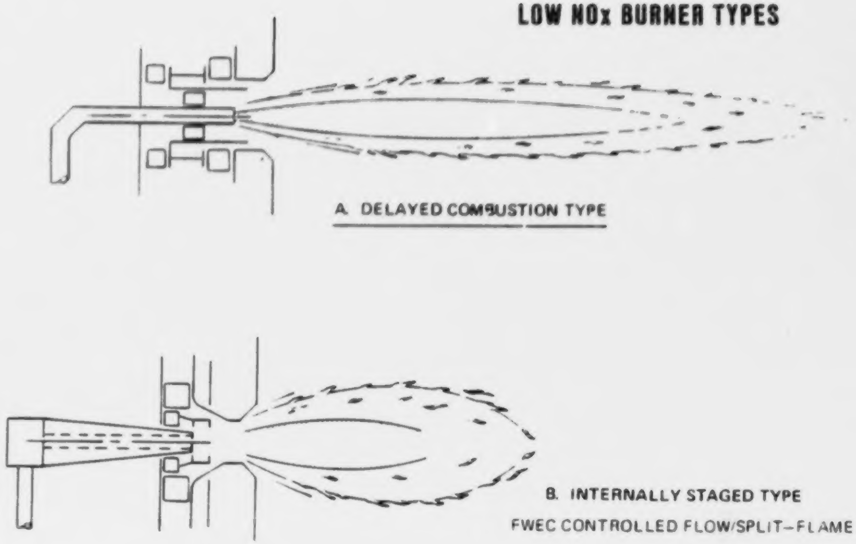

A. DELAYED COMBUSTION TYPE
B. INTERNALLY STAGED TYPE
FWEC CONTROLLED FLOW/SPLIT-FLAME

FIGURE 2

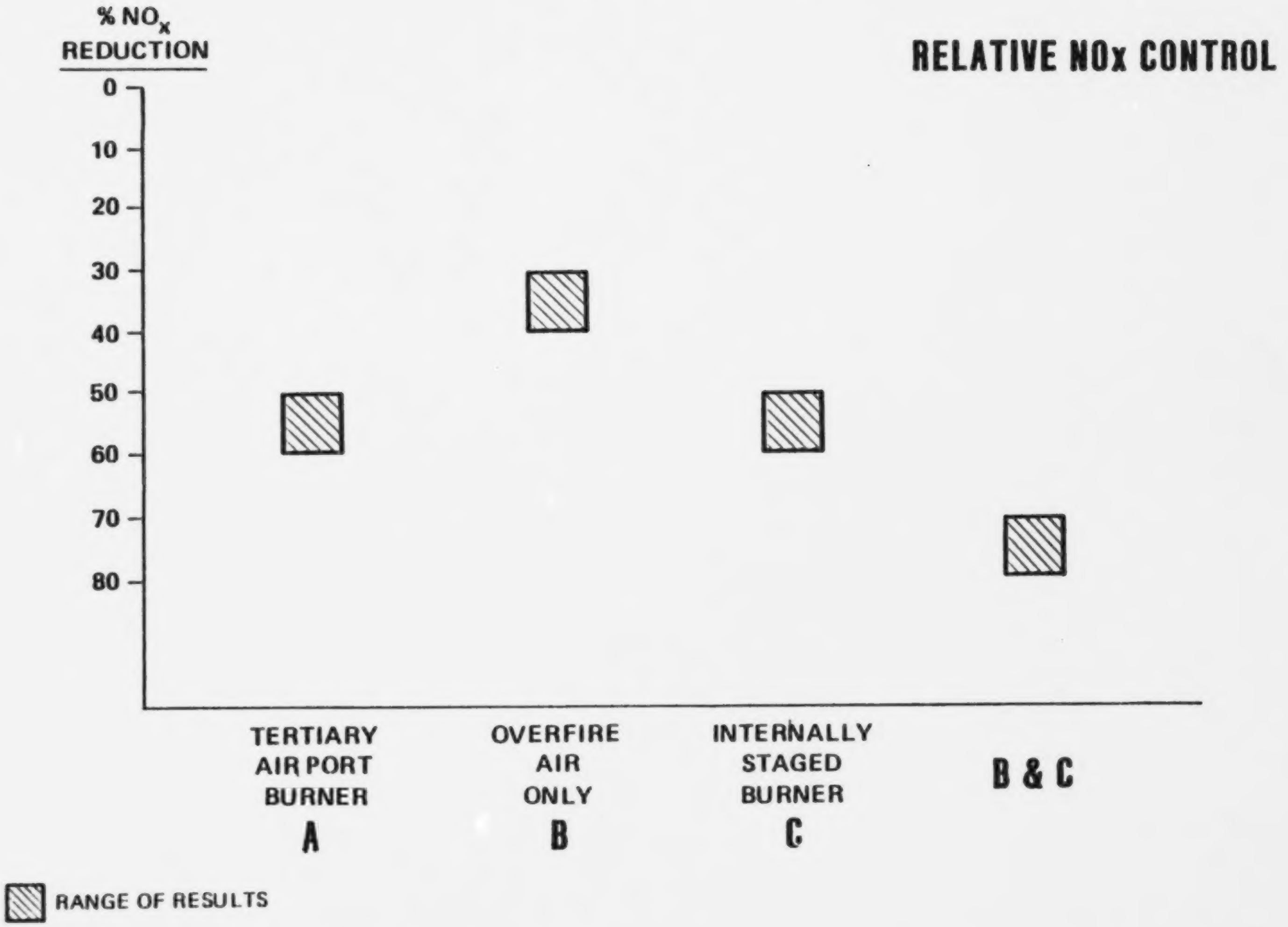
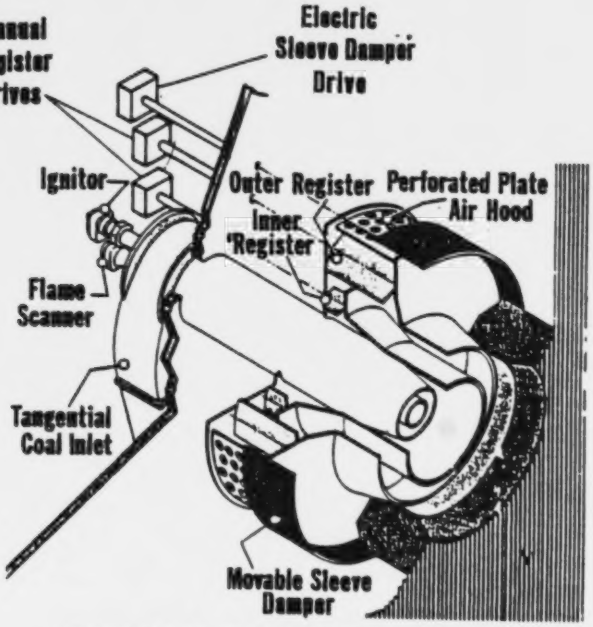
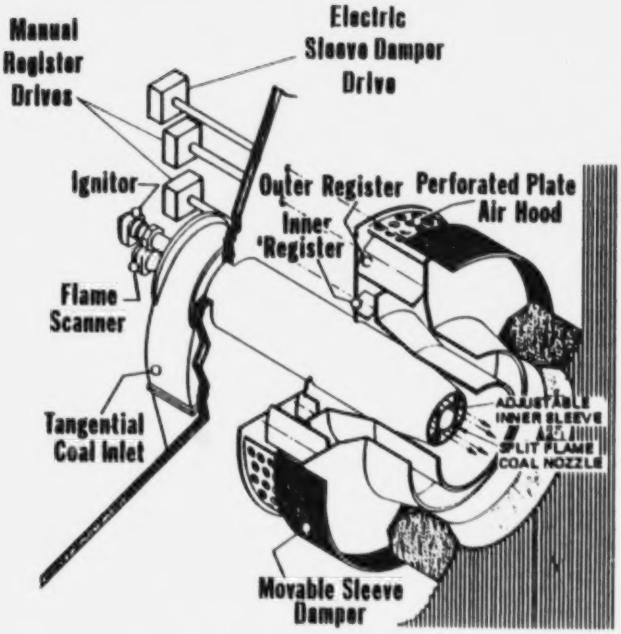

RELATIVE NOx CONTROL
% NO_x REDUCTION
0
10
20
30
40
50
60
70
80
TERTIARY AIR PORT BURNER
A
OVERFIRE AIR ONLY
B
INTERNALLY STAGED BURNER
C
B & C
RANGE OF RESULTS

FIGURE 3


Manual Register Drives
Electric Sleeve Damper Drive
Ignitor
Outer Register
Perforated Plate Air Hood
Inner Register
Flame Scanner
Tangential Coal Inlet
Movable Sleeve Damper

CONTROLLED FLOW BURNER

FIGURE 4


Manual Register Drives
Electric Sleeve Damper Drive
Ignitor
Outer Register
Perforated Plate Air Hood
Inner Register
Flame Scanner
ADJUSTABLE INNER SLEEVE AND SPLIT FLAME COAL NOZZLE
Tangential Coal Inlet
Movable Sleeve Damper

CONTROLLED FLOW SPLIT FLAME BURNER

FIGURE 5

BOUNDARY AIR SYSTEM

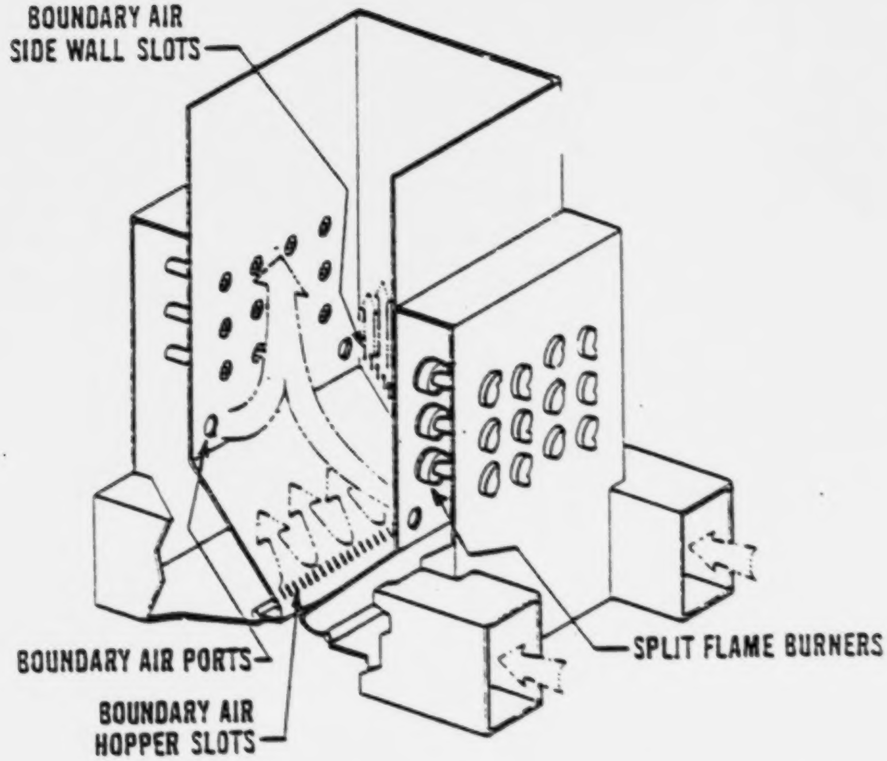
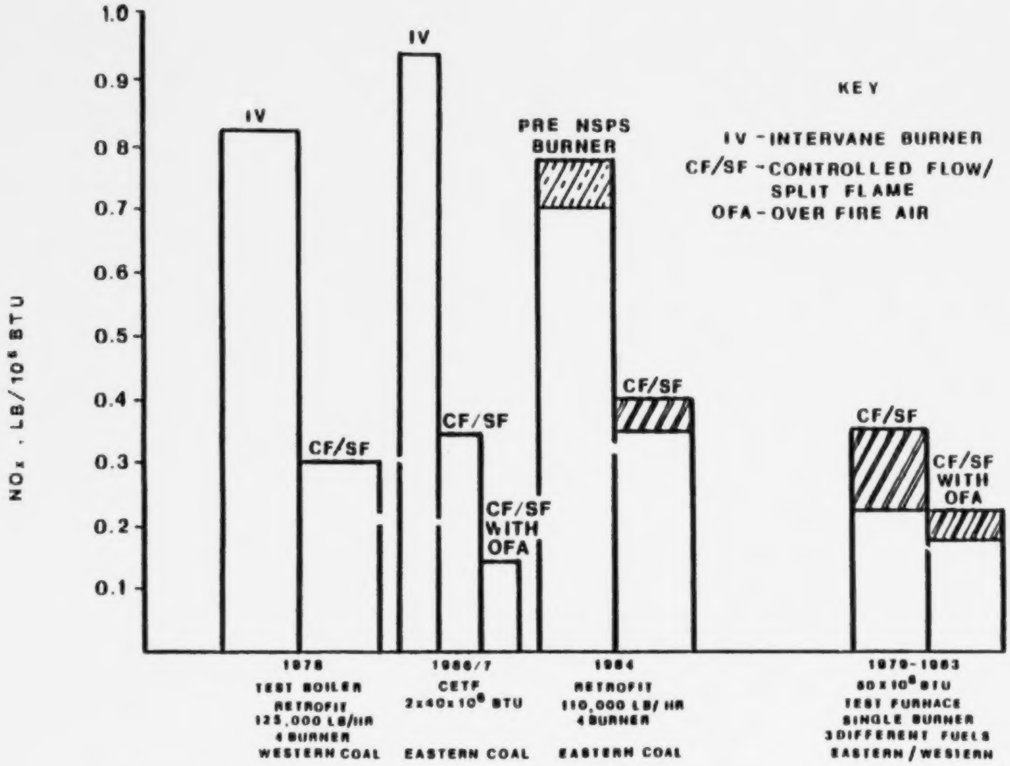

BOUNDARY AIR SIDE WALL SLOTS
BOUNDARY AIR PORTS
BOUNDARY AIR HOPPER SLOTS
SPLIT FLAME BURNERS

FIGURE 6



INDUSTRIAL SCALE LOW NOx BURNER DATA

FIGURE 7

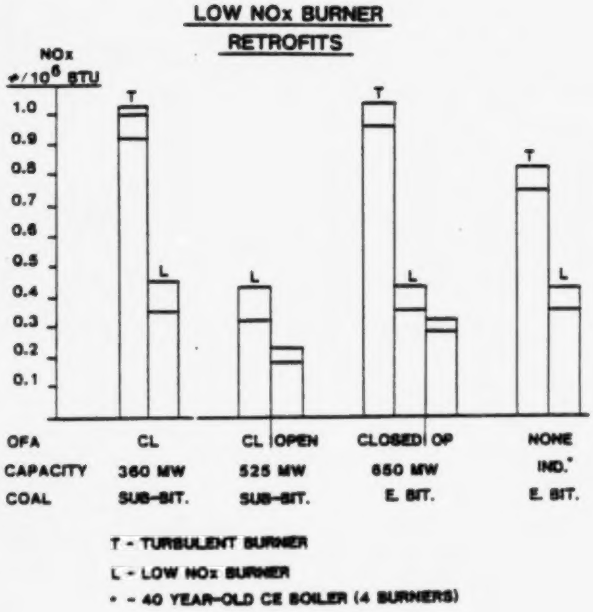
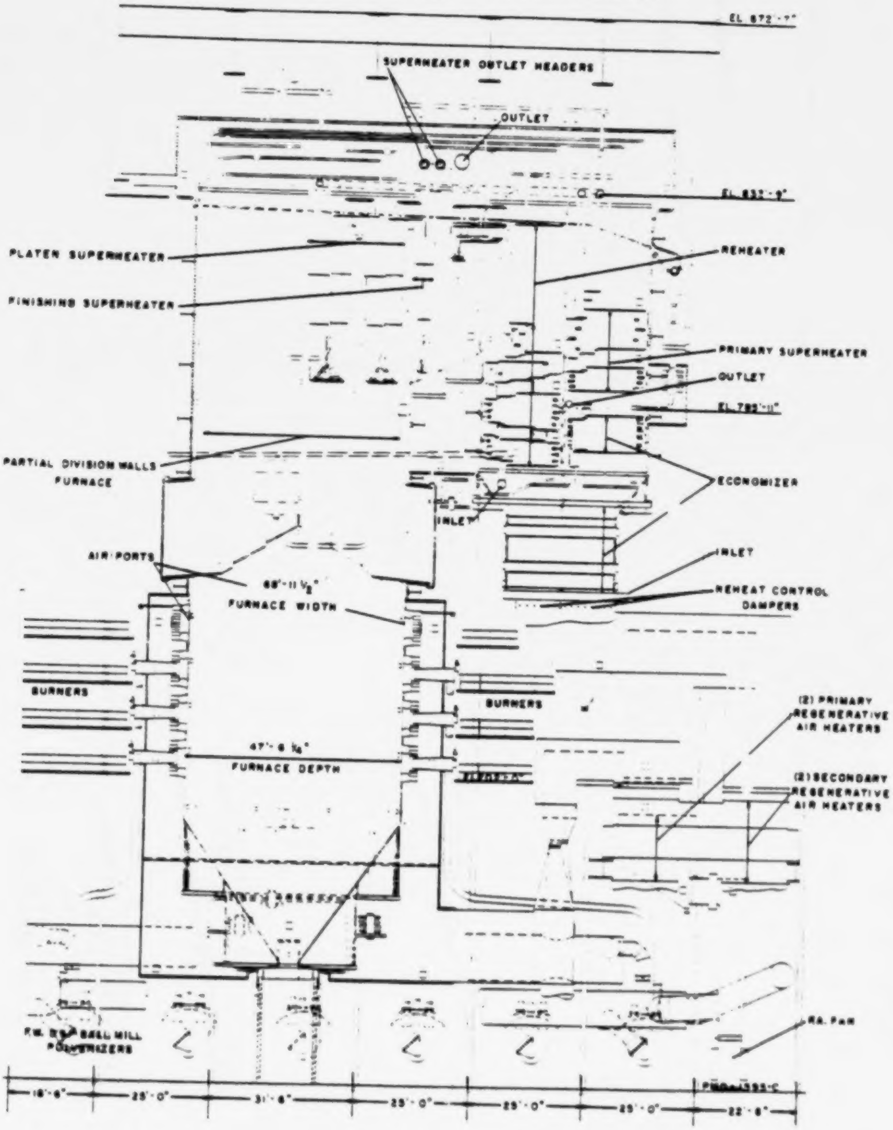


FIGURE 8

FOSTER WHEELER


EL 872'-7"
SUPERHEATER OUTLET HEADERS
OUTLET
EL 832'-9"
PLATEN SUPERHEATER
REHEATER
FINISHING SUPERHEATER
PRIMARY SUPERHEATER
OUTLET
EL 792'-11"
PARTIAL DIVISION WALLS
FURNACE
ECONOMIZER
INLET
AIR PORTS
INLET
68'-11 1/2"
FURNACE WIDTH
REHEAT CONTROL
DAMPERS
BURNERS
BURNERS
(2) PRIMARY
REGENERATIVE
AIR HEATERS
47'-6 1/4"
FURNACE DEPTH
(2) SECONDARY
REGENERATIVE
AIR HEATERS
F.W. BALL MILL
PULVERIZERS
P.A. FAN
18'-6"
25'-0"
31'-6"
25'-0"
25'-0"
25'-0"
22'-6"

PLEASANTS UNIT #2

Reproduced from
best available copy.

FIGURE 9

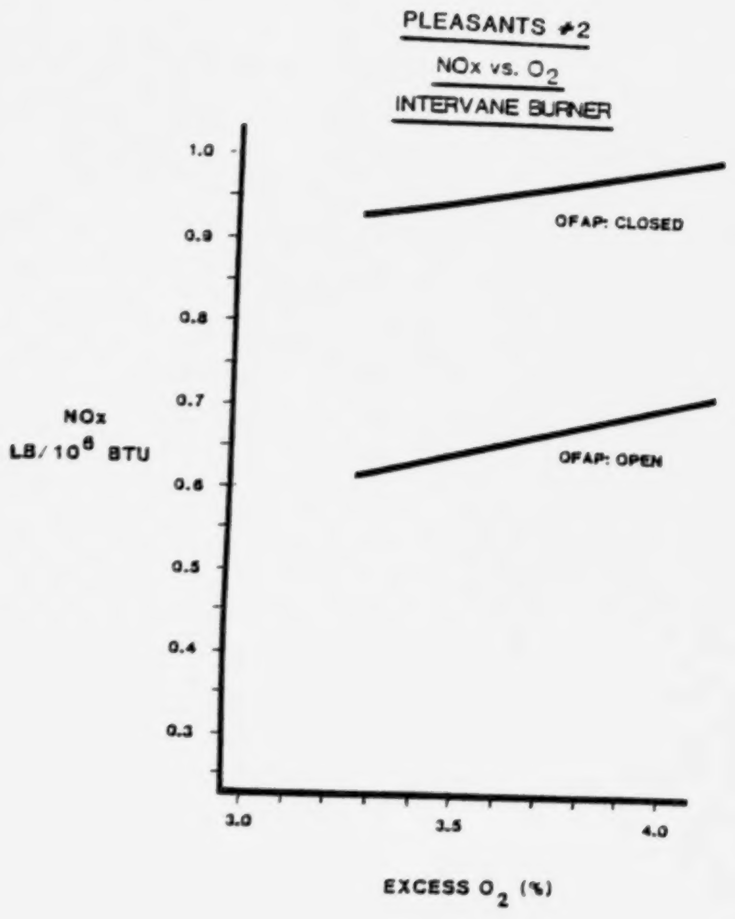


FIGURE 10

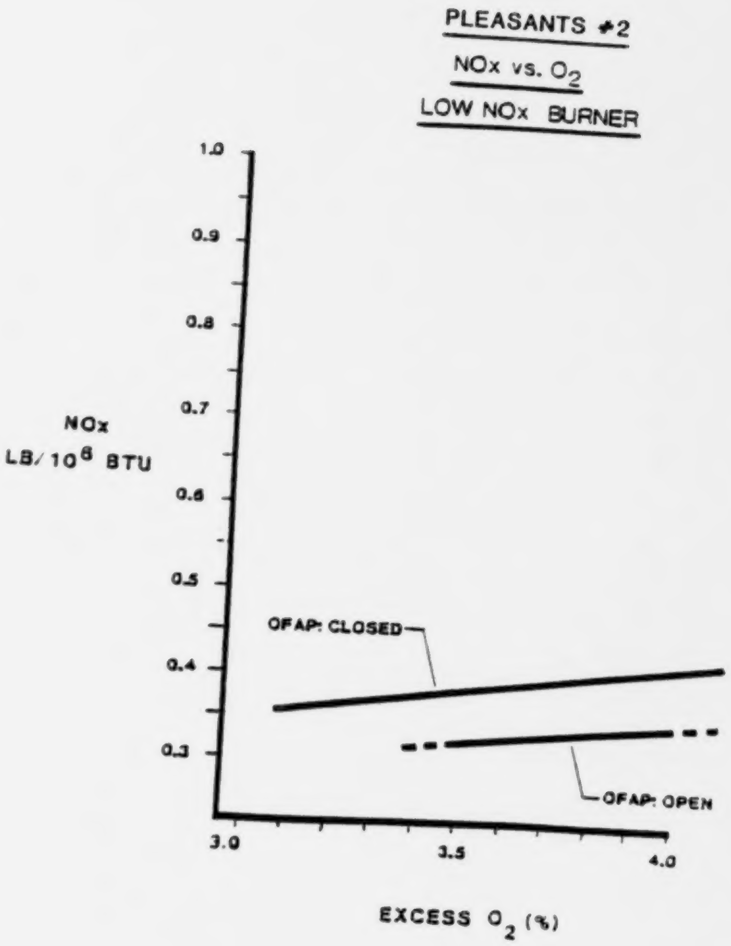
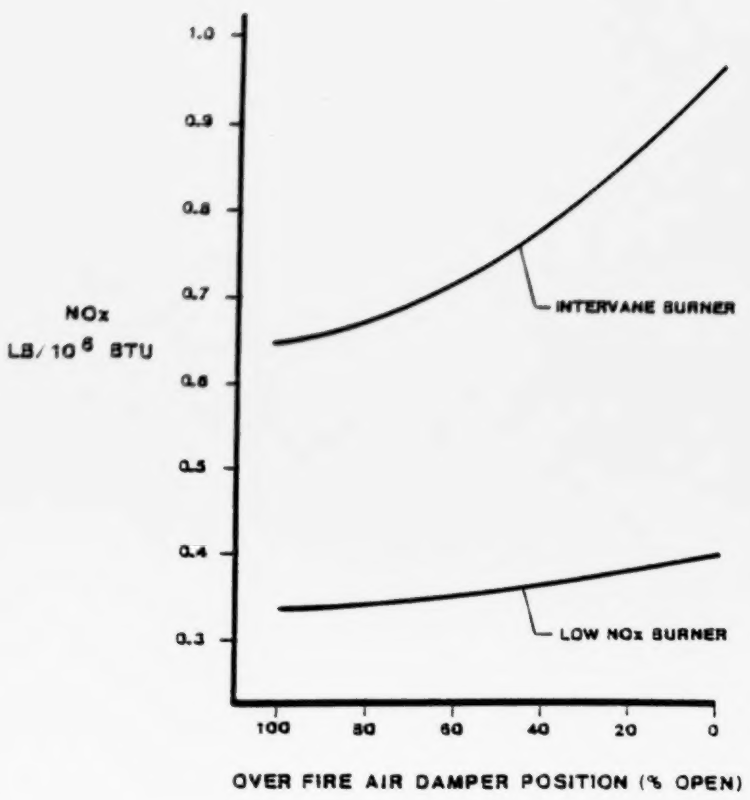


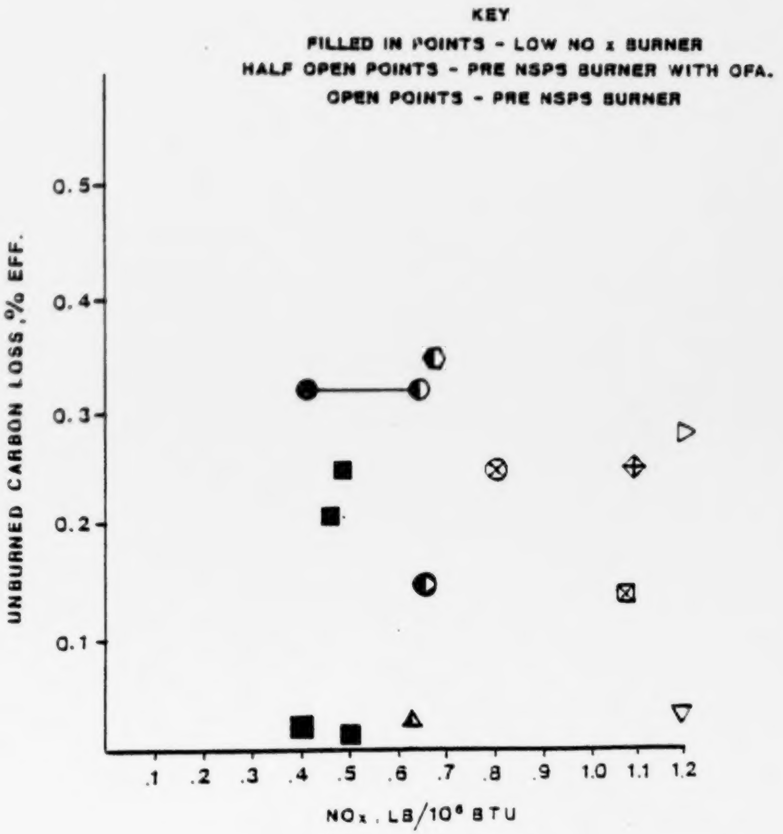
FIGURE 11



PLEASANTS #2

NOx vs. OFA

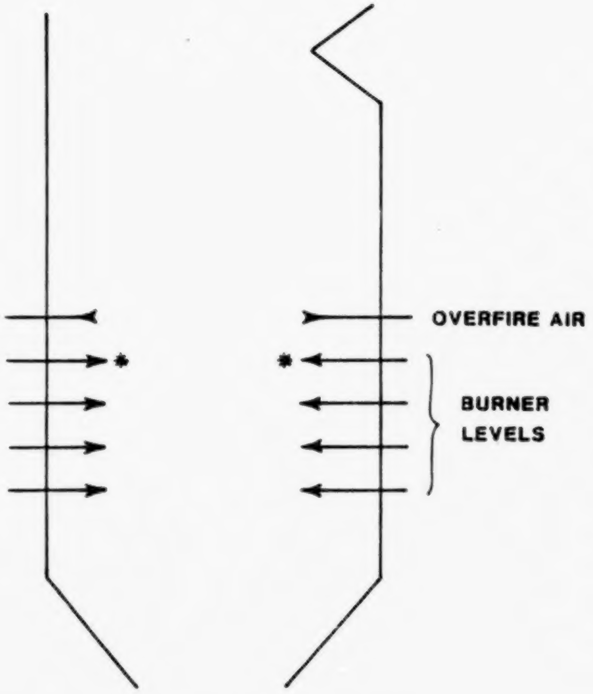
FIGURE 12



UNBURNED CARBON AND NO_x REDUCTION

FIGURE 13

LONG RESIDENCE TIME OVERFIRE AIR ARRANGEMENT


OVERFIRE AIR
*
*
BURNER LEVELS

* UNIT EQUIPPED WITH EXTRA LEVEL OF BURNERS CAN BE USED AS OVERFIRE AIR

FIGURE 14

CETF
HEAT TRANSFER SURFACE ARRANGEMENT

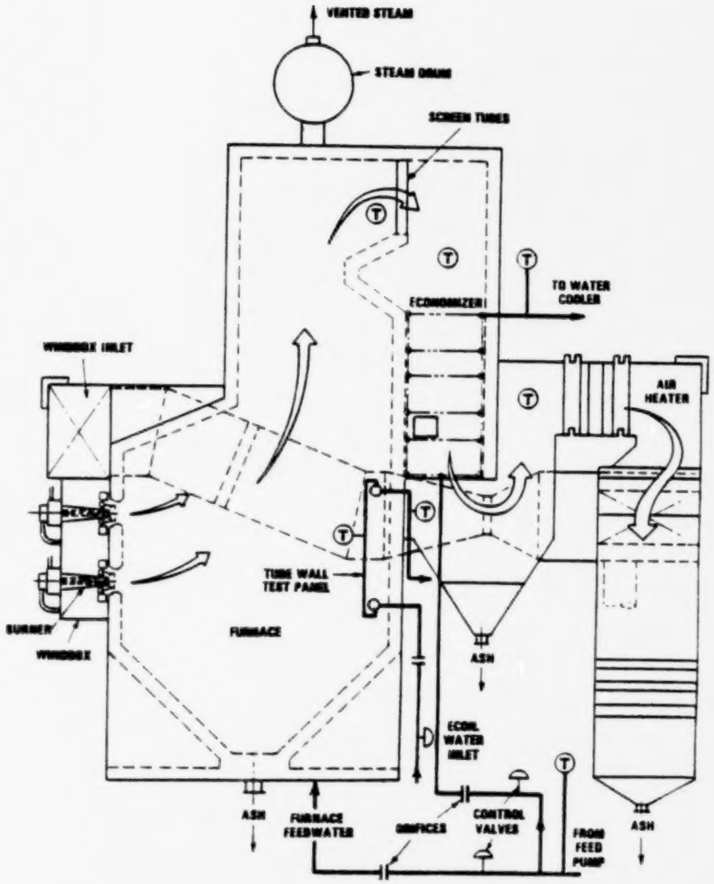

VENTED STEAM
STEAM DRUM
SCREEN TUBES
T
T
T
ECONOMIZER
TO WATER COOLER
WINDBOX INLET
T
AIR HEATER
T
T
TUBE WALL TEST PANEL
FURNACE
BURNER
WINDBOX
ASH
ECON. WATER INLET
T
ASH
FURNACE FEEDWATER
ORIFICES
CONTROL VALVES
FROM FEED PUMP
ASH

FIGURE 15

EFFECT OF OFA RESIDENCE TIME

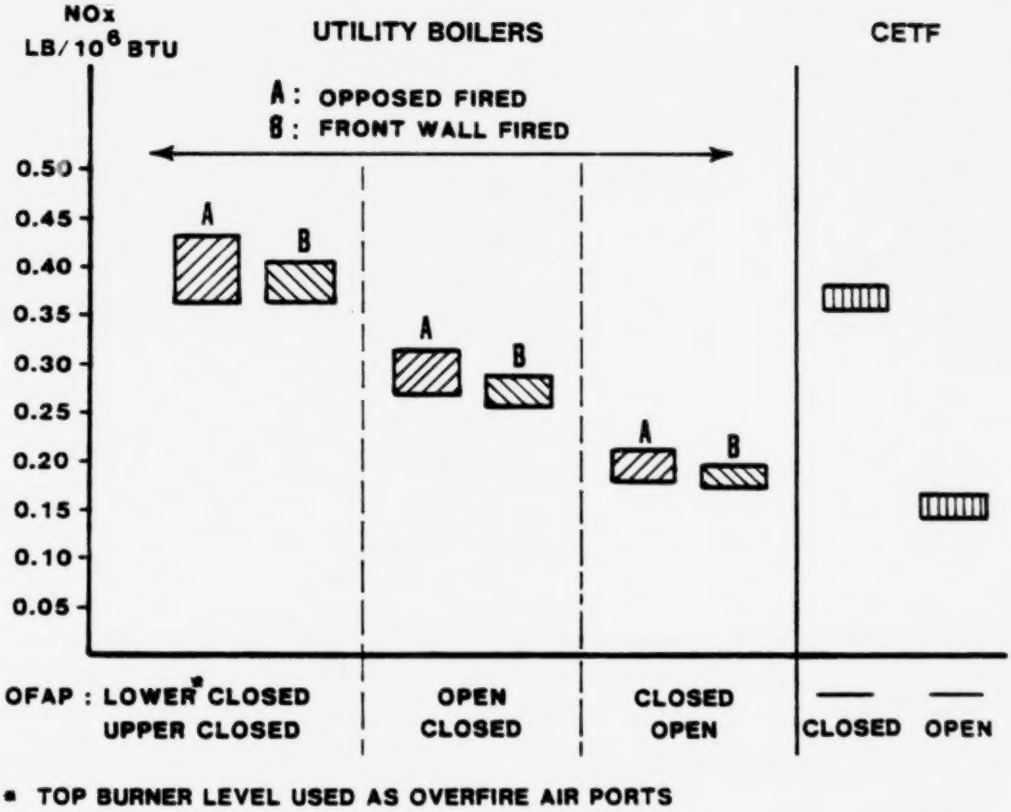
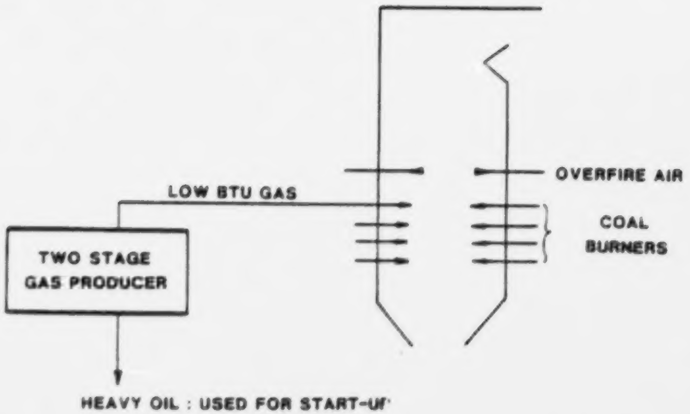


FIGURE 16


LOW BTU GAS
TWO STAGE GAS PRODUCER
HEAVY OIL : USED FOR START-UP
OVERFIRE AIR
COAL BURNERS

REBURNING WITH SYNTHETIC
COAL-DERIVED GAS

FIGURE 17

FUEL STAGING BURNER CONVERSION

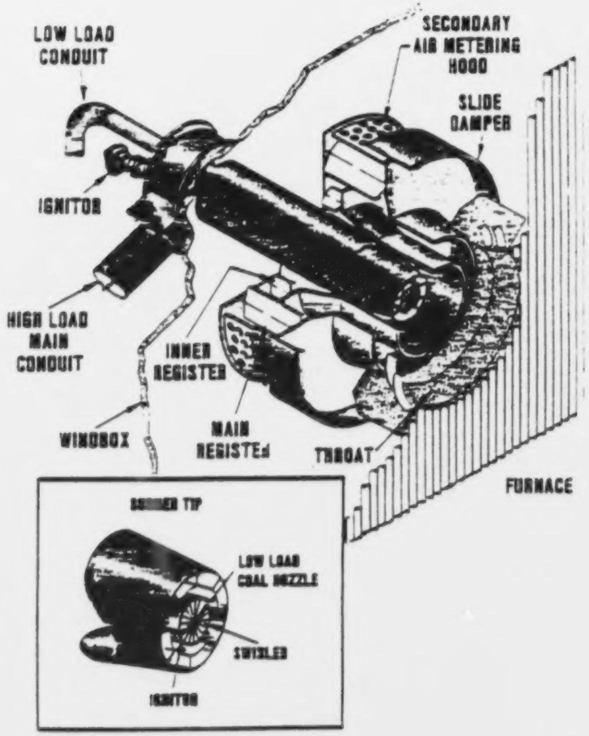

LOW LOAD CONDUIT
IGNITOR
HIGH LOAD MAIN CONDUIT
WINDBOX
INNER REGISTER
MAIN REGISTER
THROAT
SECONDARY AIR METERING HOOD
SLIDE DAMPER
FURNACE
BURNER TIP
LOW LOAD COAL NOZZLE
SWIRLER
IGNITOR

FIGURE 18

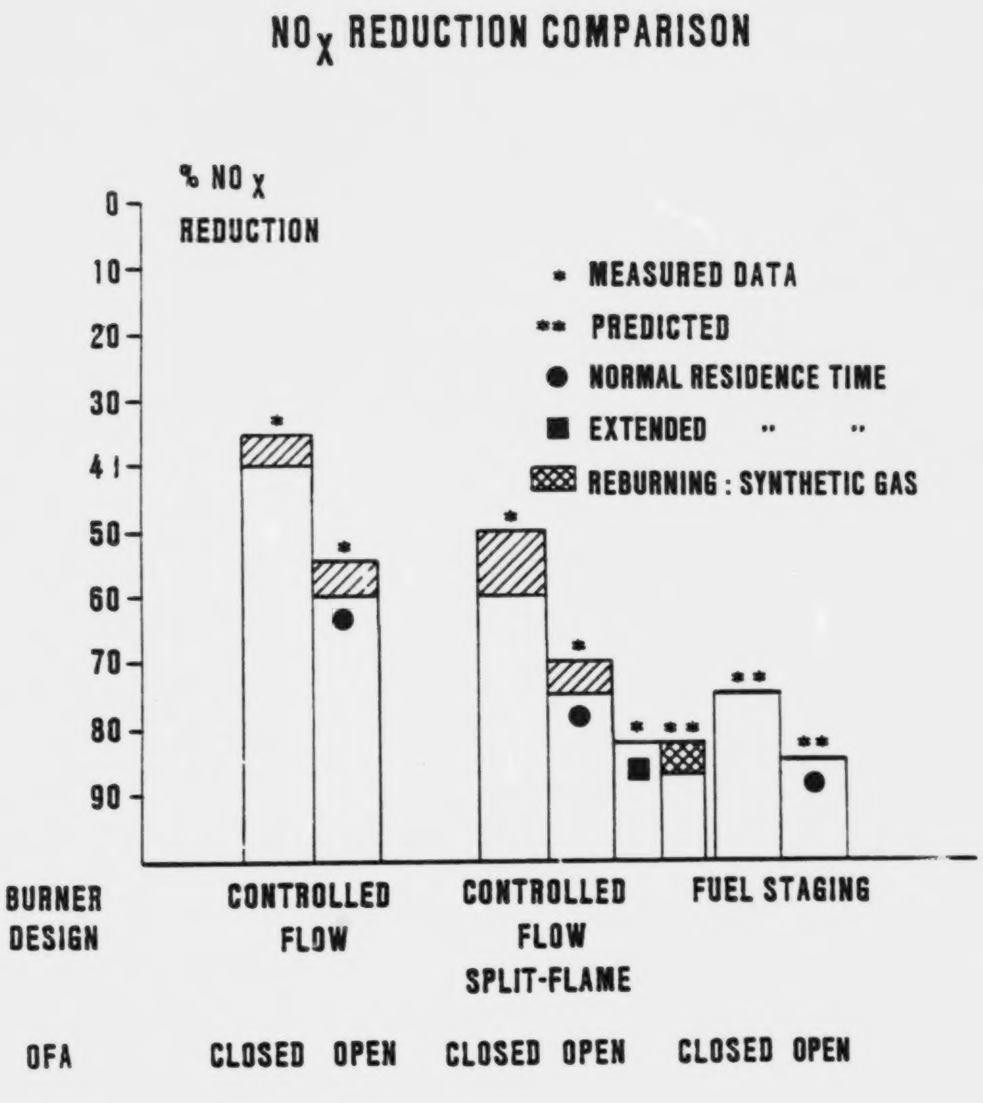
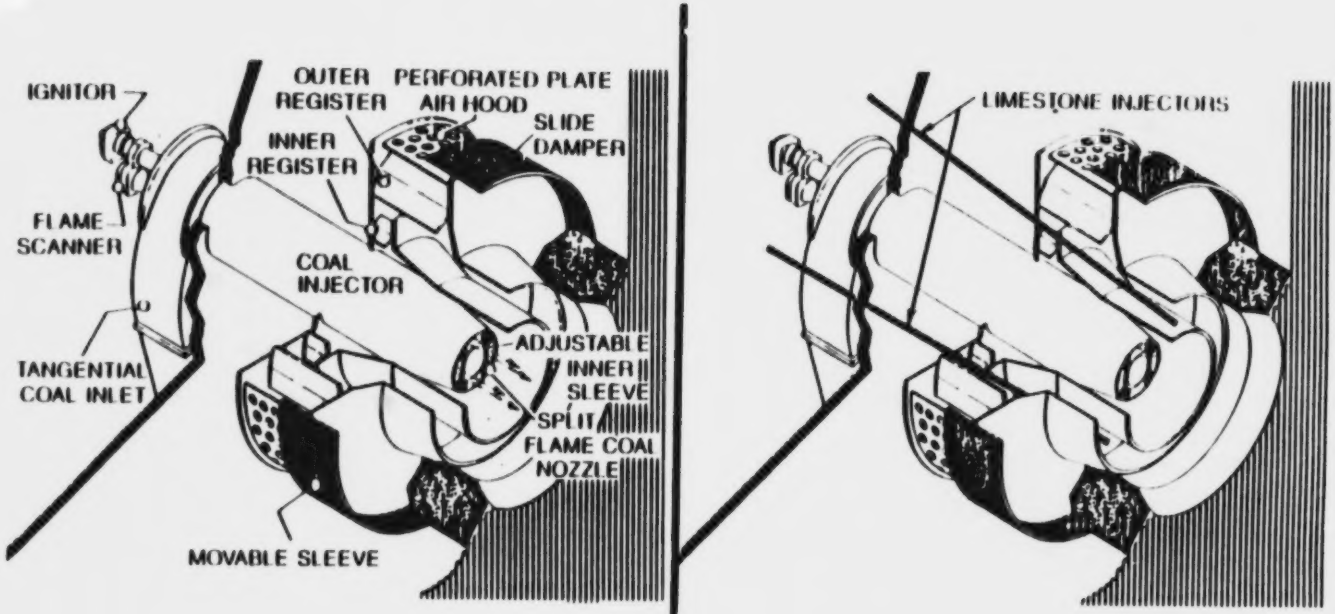

NO$_X$ REDUCTION COMPARISON
% NO$_X$ REDUCTION
0
10
20
30
41
50
60
70
80
90
* MEASURED DATA
** PREDICTED
● NORMAL RESIDENCE TIME
■ EXTENDED " "
▩ REBURNING : SYNTHETIC GAS
*
*
*
*
*
**
**
**
BURNER DESIGN
CONTROLLED FLOW
CONTROLLED FLOW SPLIT-FLAME
FUEL STAGING
OFA
CLOSED
OPEN
CLOSED
OPEN
CLOSED
OPEN

FIGURE 19


IGNITOR
FLAME SCANNER
TANGENTIAL COAL INLET
OUTER REGISTER
INNER REGISTER
PERFORATED PLATE AIR HOOD
SLIDE DAMPER
COAL INJECTOR
ADJUSTABLE INNER SLEEVE
SPLIT FLAME COAL NOZZLE
MOVABLE SLEEVE
LIMESTONE INJECTORS

Controlled Flow/Split Flame Low NO_x Burner

Low NO_x Burner with Integral Limestone Injectors

FIGURE 20

SO_2 REDUCTION
IN-BURNER vs. UPPER FURNACE INJECTION

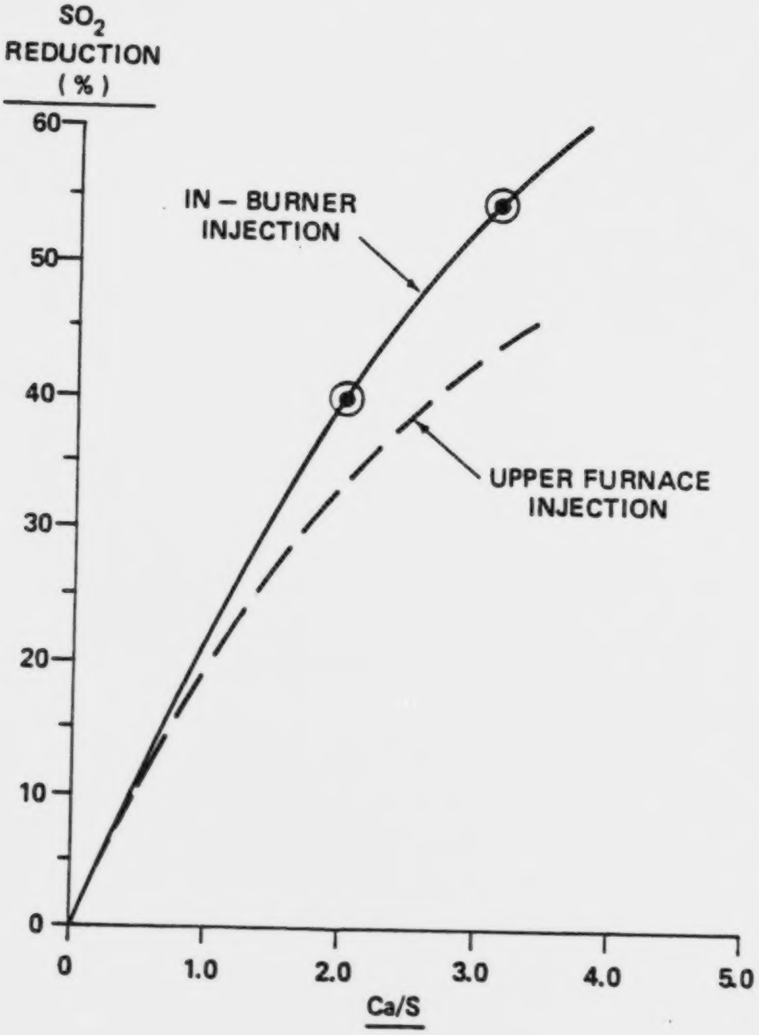


FIGURE 21

NOx REDUCTION SUMMARY

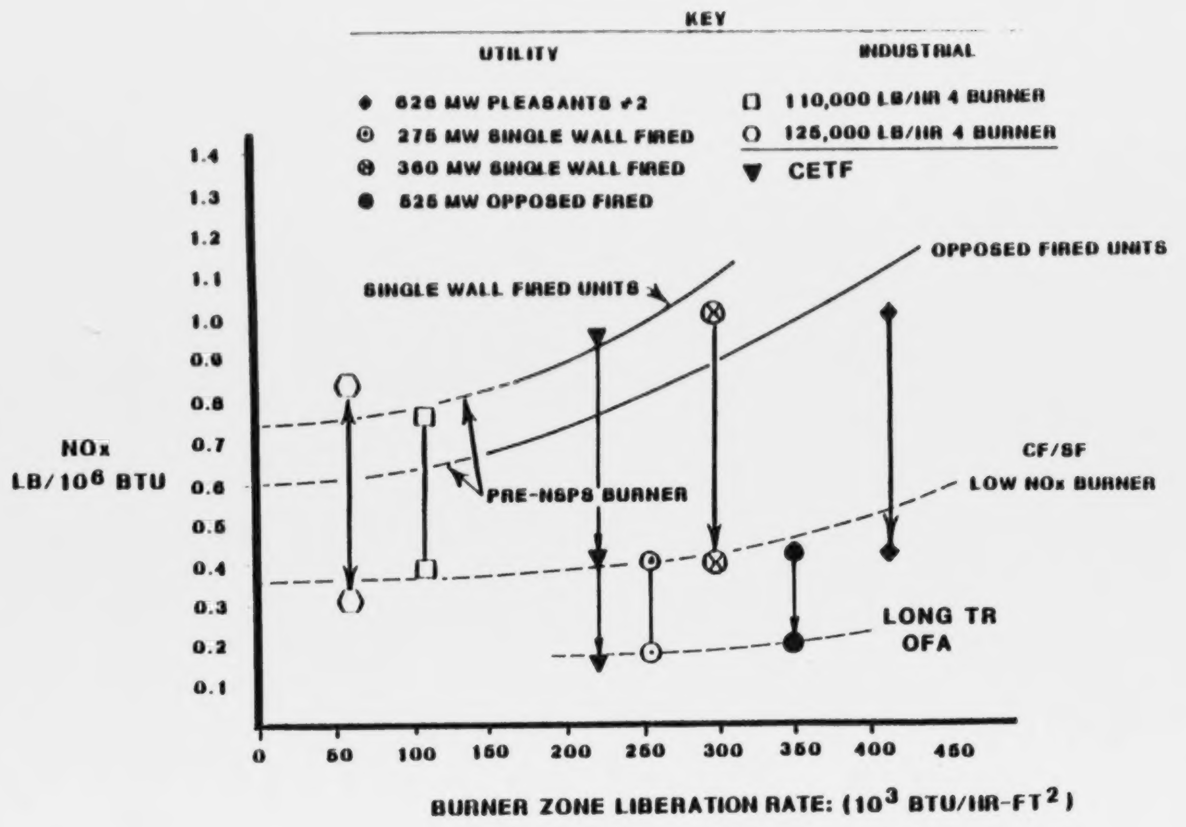


FIGURE 22

NOx CONTROL UPDATE - 1987

Albert D. LaRue
Paul L. Cioffi
Domestic Fossil Operations
Babcock & Wilcox
Barberton, Ohio

ABSTRACT

Babcock & Wilcox is expanding its low NOx technology and product lines to include systems directly suited for uncontrolled sources and for an increasing variety of new boiler applications. The low NOx cell burner has successfully completed two scales of combustion testing and initial field trials, and awaits a full boiler demonstration. The XCL burner was developed to reduce NOx below existing low NOx burner capabilities while providing individual burner air flow measurement and other features to improve performance. Reburning is being investigated as a NOx control measure for cyclone-fired boilers. NOx emissions are controlled with gas- and oil-fired units by use of PG-Dual Register Burners combined with NOx ports and gas recirculation. Further NOx reduction can be achieved by use of In-Furnace NOx Reduction. Fluid beds provide NOx control by virtue of the combustion methodology, and lower NOx levels can be reached by staging. Refuse systems often face a wide range of emission limitations and the Controlled Combustion Zone (CCZ$^{\text{TM}}$) furnace offers potential for improved combustion and lower NOx when firing refuse-derived fuel. An update is provided here on the technology and products used by B&W to control NOx emissions in these applications.

INTRODUCTION

This paper deals with systems offered by Babcock & Wilcox to control emissions of nitric oxides during combustion in utility and industrial steam generation equipment. The major fuels which are considered include coal (in several forms), biomass, refuse, fuel oil, and natural gas. The combustion systems range from low NOx circular-type burners to cyclones, to stokers to fluidized beds. Some of these systems are primarily suited for new units, while others have been specifically designed for retrofit application to existing sources.

This variety of combustion systems reflects the market for steam generation equipment in the United States. New orders for conventional utility fossil-fired boilers peaked at over 35,000 megawatts/year during the early 70's, declined to '70s, declined to the 5000 MW level by the end of that decade, and hit zero in 1983. Present levels are near 1000 MW/year and expected to remain low into the early '90s. A resurgence then is expected to include fluidized beds and combined cycle with (or without) coal gasification, in addition to conventional units. For now and the near future, the fossil utility market has transformed from capacity additions to capacity preservation and upgrades. The industrial market also peaked in the early 70's, at levels of over 70 million pounds of steam/year and has declined and stabilized in the 20 to 30 million pound range. The industrial market continues to see significant activity in a diverse group topped by turbine exhaust generators, waste heat boilers and package boilers; and including fluid bed, refuse, process recovery, and conventional fossil-fired boilers.

All new steam generating equipment in excess of 250 million Btu/hr input firing gas, oil, or coal are subject to Federal New Source Performance Standards (NSPS) limiting NOx emissions. In addition, these units may face more stringent requirements enacted by state legislation, or to comply with Ambient Air Quality Standards or Prevention of Significant Deterioration Criteria. In contrast, most pre-NSPS units are not presently required to control NOx emissions. Many of these units emit NOx at two or three times the level of present NSPS limitations. So-called acid rain legislation is expected to eventually regulate SO_2 and NOx emissions for some portion of this population. Enactment of this legislation often appears near, but its impact is likely to be a dozen years off. In the meantime, some states are instituting their own plans which limit emissions from uncontrolled sources. In the long run, the most likely targets for emission controls are large, coal-fired, pre-NSPS utility boilers in the central and northeastern portion of the country. Consequently, manufacturers of steam generating and combustion equipment, with the support of interested institutes and agencies, are endeavoring to develop low NOx combustion systems applicable to these existing units. Some of the pre-NSPS coal-fired combustion systems can readily be replaced or augmented with standard present day low NOx equipment e.g. simple burner replacement or NOx port addition. Other cases are faced with extensive boiler modifications, derates, or downstream clean-up equipment, unless more compatible low NOx systems are developed to addresss these situations. Two such cases figure prominently in units of B&W manufacture: the cell burner and the cyclone. B&W is actively involved in programs to develop low NOx systems for both cases.

This paper will provide an overview of B&W combustion systems which are commercially available or under development, for new or retrofit use in utility and industrial steam generation equipment. The discussion is organized by fuel form--solids, liquids, gas--primarily due to the widening variety of solid fuels of interest and due to a narrowing of differences in systems once considered either utility or industrial.

SOLID FUELS

PULVERIZED COAL

Dual Register Burner

Pulverized coal is the dominant fuel for electric power production in the United States. Limitations on NOx emissions from new PC-fired boilers were enacted in 1971, and Babcock & Wilcox responded with a new combustion system to meet the standards. The combustion system consists of the Dual Register Burner, compartmented windbox, enlarged combustion zone, and NOx ports when necessary (Figure 1). This system has successfully met all applicable NOx emission limitations, ranging from 0.7 to 0.45 lb NO/million Btu (lb/MKB), as actual emissions ranged from 0.7 to 0.2 lb/MKB (1). This system is in use in 65 boilers representing 36,800 MW's of capacity in the United States. Table 1 lists the range of boiler sizes, burner capacities, and fuels for the DRB. The Dual

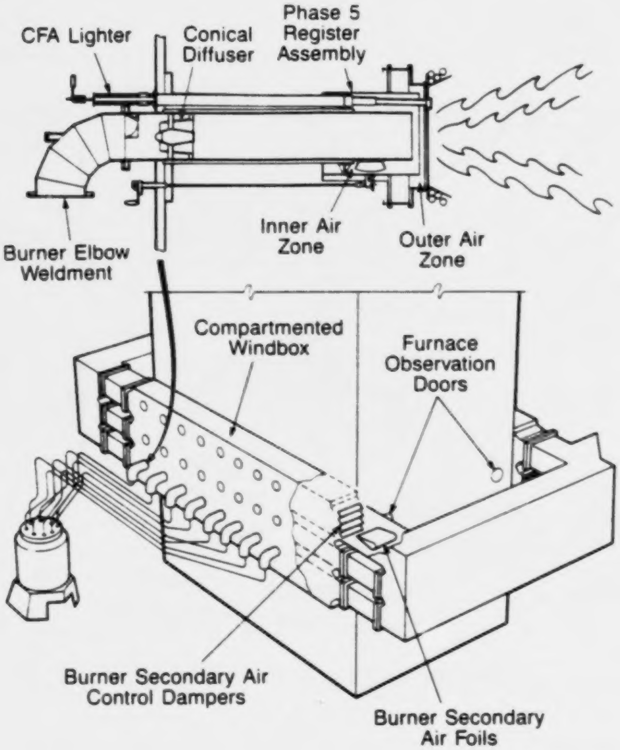

CFA Lighter
Conical Diffuser
Phase 5 Register Assembly
Inner Air Zone
Outer Air Zone
Burner Elbow Weldment
Compartmented Windbox
Furnace Observation Doors
Burner Secondary Air Control Dampers
Burner Secondary Air Foils

Figure 1 Phase V dual register burner and compartmented windbox.

Table 1. DUAL REGISTER BURNER EXPERIENCE

Units in service	65	
Combined capacity (MW's)	36,800	
Smallest unit	65 MW (3 mills/6 burners)	
Largest units	1300 MW (14 mills/98 burners)	
DRB capacity range		
Minimum	1.5 MKB (Lab)/98 MKB (Field)	
Maximum	218 MKB (Field)	
Fuel Ranges - coal	Minimum	Maximum
Moisture	3	35
Volatile Matter	19	40
Ash	4	35
Heating Value	4,900	13,900
-Fuel Oil		
-Natural Gas		

Register Burner is also being applied internationally in Canada, Italy, Japan, Korea, Spain, and Taiwan.

Enhanced Ignition Burner

The international scene for new utility steam generators is quite active in some countries. Indigenous coal reserves may be substantial and economically favored, though exhibiting difficult combustion characteristics. For example, the People's Republic of China has entered a period of rapid power generation growth with reliance on a wealth of domestic coal reserves. However, many of the coals are low in volatile matter with relatively high ash contents (Table 2), and would result in unsatisfactory ignition performance with conventional burners. NOx

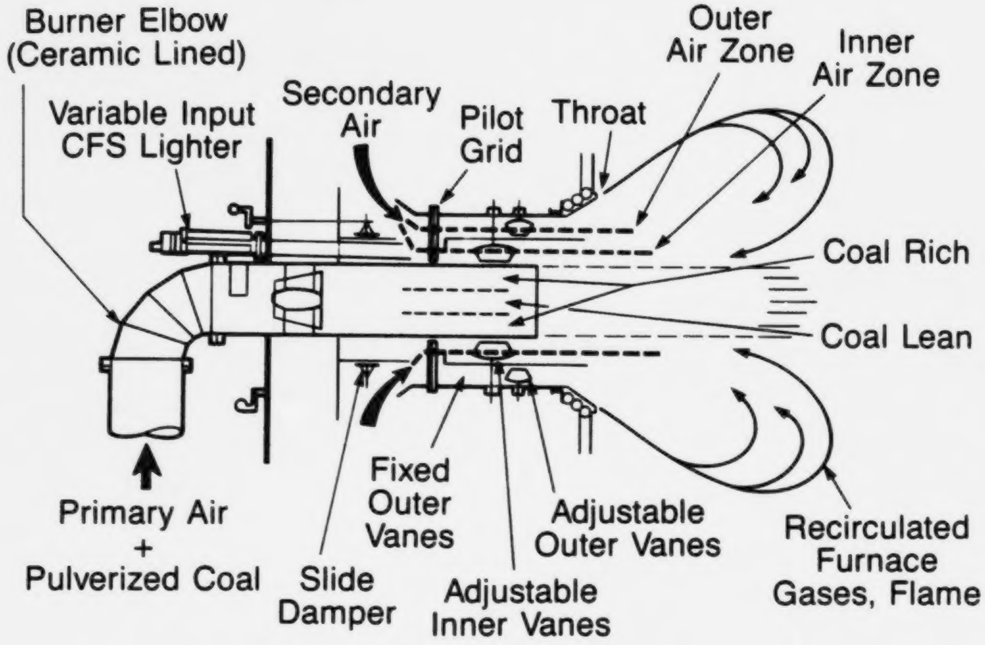

Burner Elbow (Ceramic Lined)
Variable Input CFS Lighter
Secondary Air
Pilot Grid
Throat
Outer Air Zone
Inner Air Zone
Coal Rich
Coal Lean
Primary Air + Pulverized Coal
Slide Damper
Fixed Outer Vanes
Adjustable Inner Vanes
Adjustable Outer Vanes
Recirculated Furnace Gases, Flame

Figure 2 Enhanced ignition burner.

Table 2 LOW VOLATILE COALS FROM PEOPLE'S REPUBLIC OF CHINA

Moisture	5.7	5.3	6.3	7.0
Ash	17.9	18.0	23.1	21.5
Volatile Matter	5.4	6.9	13.4	10.7
Fixed Carbon	71.0	69.8	57.2	60.8
HHV (Btu/lb)	11309	11086	10420	10800

emission control is also a consideration. Babcock & Wilcox has developed the Enhanced Ignition-Dual Register Burner for low NOx performance with difficult to burn fuels (Figure 2). The Enhanced Ignition-DRB accomplishes this by reducing fuel jet momentum in the ignition zone and increasing hot gas recirculation to the ignition zone by flow proportion and swirl from the two air zones. The slow dispersion of the fuel jet acts to limit NOx formation.

Primary Air Exchange Burner

For coals with very low volatile matter, such as semi-Anthracites and Anthracites, further provisions are required to obtain satisfactory ignition performance. With such coals, volatile matter has diminished to such an extent that the heat it contributes to the burner ignition zone is insufficient to sustain ignition. Temperature in the ignition zone has to be increased by controlling heat loss, returning heat from char reactions to the ignition zone, and further preheating the air and fuel prior to its introduction to the burner. B&W developed the Primary Air Exchange (PAX) Burner (Figure 3) for these applications. The PAX burner utilizes a device in the burner nozzle to vent off primary air and replace it with hot air to preheat the fuel immediately prior to ignition. The low velocity fuel jet enters the ignition zone where the dual register design (derived from the Enhanced Ignition-DRB) promotes hot gas recirculation from downstream char reactions back along the incoming fuel jet. The extracted primary air,

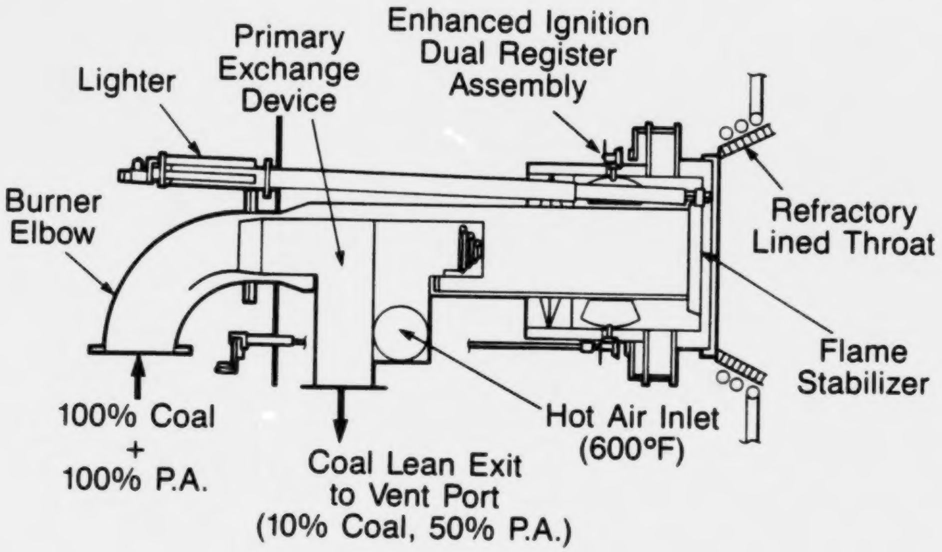

Enhanced Ignition
Dual Register
Assembly
Primary
Exchange
Device
Lighter
Burner
Elbow
Refractory
Lined Throat
Flame
Stabilizer
100% Coal
+
100% P.A.
Coal Lean Exit
to Vent Port
(10% Coal, 50% P.A.)
Hot Air Inlet
(600°F)

Figure 3 Primary air exchange burner.

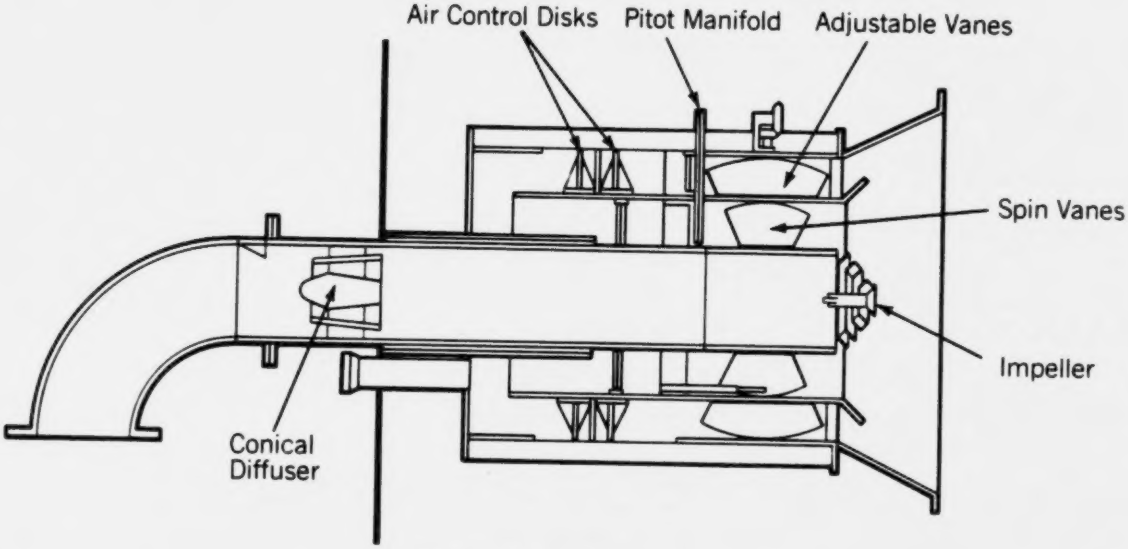

Air Control Disks
Pitot Manifold
Adjustable Vanes
Spin Vanes
Impeller
Conical
Diffuser

Figure 4 XCL burner.

accompanied by a small percentage of the coal, is vented into the furnace and uses the main burner as its ignition source.

XCL Burner

In the United States, several factors have led to a need for combustion equipment capable of NOx emissions lower than presently possible, e.g. BACT in non-attainment areas or other locally strict limitations. Two-stage combustion can greatly reduce NOx but tends to increase operational problems due to slagging and corrosion. In addition, retrofit applications are often constrained by a lack of space for the ductwork and NOx ports associated with staged combustion. As a result, B&W has developed the XCL burner (Figure 4) for new or retrofit low NOx applications. The functional design of the XCL burner is derived from Babcock

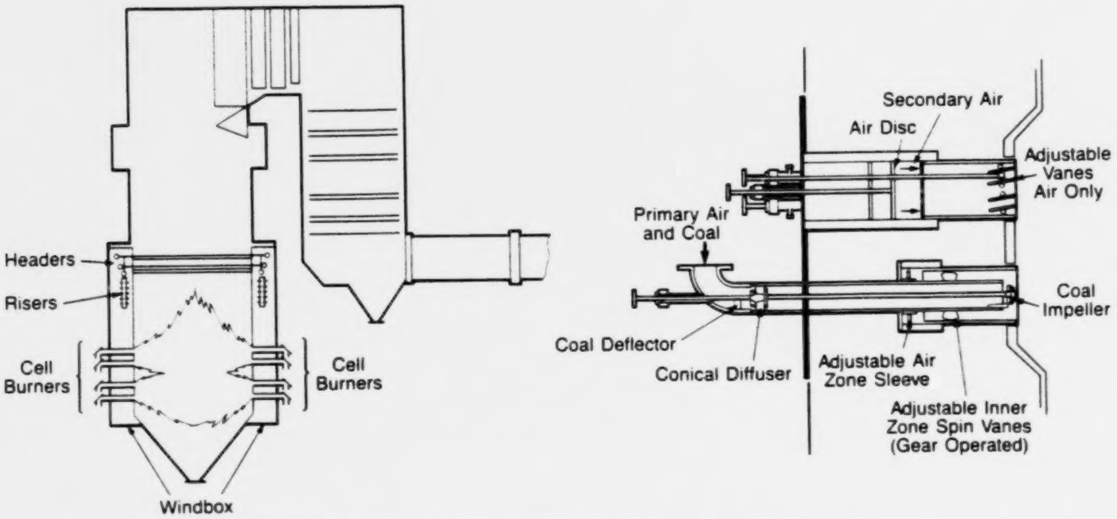


Figure 5 Low NO$_X$ cell burner for utility boiler retrofit.

Hitachi's HT-NR burner and its predecessor the Dual Register Burner (2). The XCL is configured mechanically to accommodate a pitot-grid air measuring device to measure air flow independently to each burner, and with a sliding damper to regulate air flow. Adjustable inner vanes and dual stage vanes in the outer air zone provide efficient swirl control with improved peripheral air distribution, and with minimal air side resistance. With support by the EPA, the XCL burner was extensively tested in their Large Watertube Simulator (LWS) facility at the 80 MKB scale (3). NOx emissions were reduced over 70 percent relative to uncontrolled levels (firing Pittsburgh 8 coal) while simultaneously limiting unburned combustibles to 2 to 7 percent (excellent for this facility). Additional work was performed to prepare the XCL burner for the LIMB demonstration in Ohio Edison's Edgewater Station, Unit 4. In particular, an impeller mixing device was developed to provide the capability of varying flame length and NOx to tune the burner to the furnace in retrofit applications. A full complement of XCL burners was retrofitted to the unit in September 1986. NOx emissions in the 0.3 to 0.5 lb/MKB are regularly being achieved, however, air/fuel imbalance problems need resolution (in progress at this writing) to reduce unburned carbon to targeted limits (4).

Low NOx Cell Burner

The Low Cell Burner, for which pilot scale results were reported in the 1985 Boston Symposium, has since successfully completed large scale tests in readiness for commercialization. Of note, the low NOx cell is being developed for direct retrofit to units equipped with with dual-throat cell-type burners (Figure 5) which are in use in over 23,000 MW's of capacity in the U.S (5). With EPRI support, the low NOx cell was tested at the 100 MKB scale in multiburner tests in the LWS facility. The low NOx cell produced NOx reduction up to 75 percent, relative to standard cell with excellent combustion efficiency (6). Further development work indicated a strong relationship between NOx and flame length, with maximum NOx reduction corresponding to longest flames. Flame length can be tuned with impellers if field conditions dictate. In addition to these tests, a full scale prototype low NOx cell was built and installed at Dayton Power & Light's Stuart Station, Unit 3. For two years, the low NOx cell has proven its mechanical reliability and air flow measurement capability. Local furnace corrosion has been tested for by UT measurements of wall tubes and no tube wastage is apparent. The low NOx cell is now ready for full-boiler demonstration, either domestically or internationally.

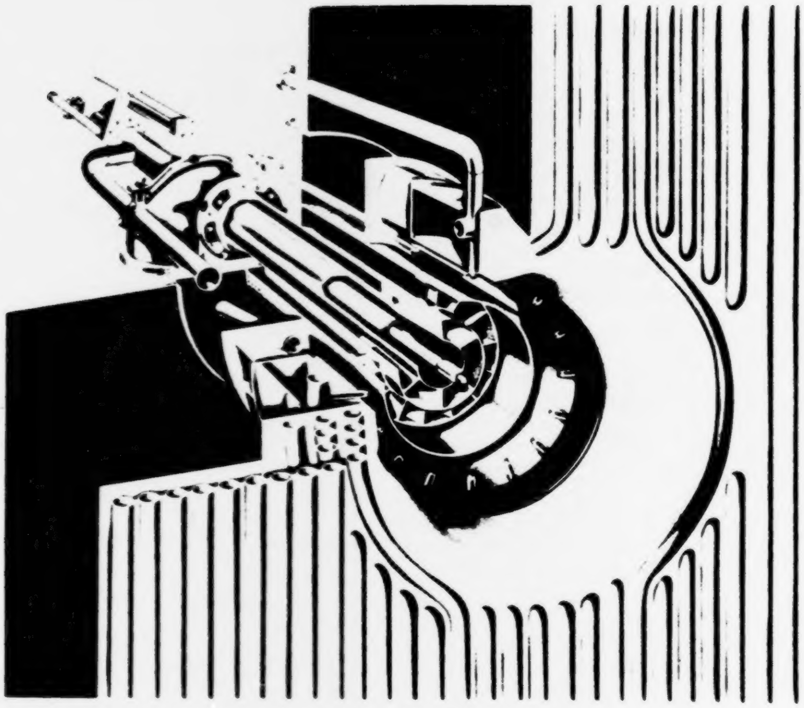


Figure 6 Adjustable swirl burner.

Adjustable Swirl Burner

The Adjustable Swirl Burner (ASB) (Figure 6) was developed in the early 1980's to satisfy NSPS for NOx emissions in PC-fired industrial boilers. The ASB is capable of 0.5 to 0.6 lb/MKB NOx emissions firing bituminous coal in industrial boilers, without resorting to two staged combustion. The Adjustable Swirl Burner is designed for firing natural gas or fuel oil, as frequently encountered in industrial applications. NOx control with oil and gas can be augmented by NOx ports.

CYCLONE FURNACE

Crushed coal is fired in cyclones of utility boilers totaling 23,000 MW of capacity, as well as in numerous industrial boilers. The design of the cyclone and auxiliary equipment does not lend itself to in-place alterations to reduce NOx. Two stage operation is ill-advised due to associated slag tapping problems and the potental for making present corrosion problems even worse. Reburning offers promise for NOx reduction in cyclone-fired boilers since it could be applied in a manner that would have little impact on the cyclone itself. A reburning fuel, preferably natural gas, would be fired in the main furnace to accomplish NOx reduction. Full scale demonstrations of this approach have been proposed recently, however, it would be prudent to defer "demonstration" until smaller scale work is performed to characterize performance and NOx reduction potential. EPRI and GRI are co-sponsoring pilot tests in B&W's cyclone-fired Small Boiler Simulator facility (Figure 7). Reburning tests will be conducted beginning spring 1987. This same facility was recently used to evaluate furnace sorbent injection for SO_2 control with cyclones. Due to the cyclone inherent high quench rate environment (1200°F/sec) within the sulfation temperature window ($2300-1600^{\circ}$F), a hydrated dolomitic lime sorbent was necessary to provide the

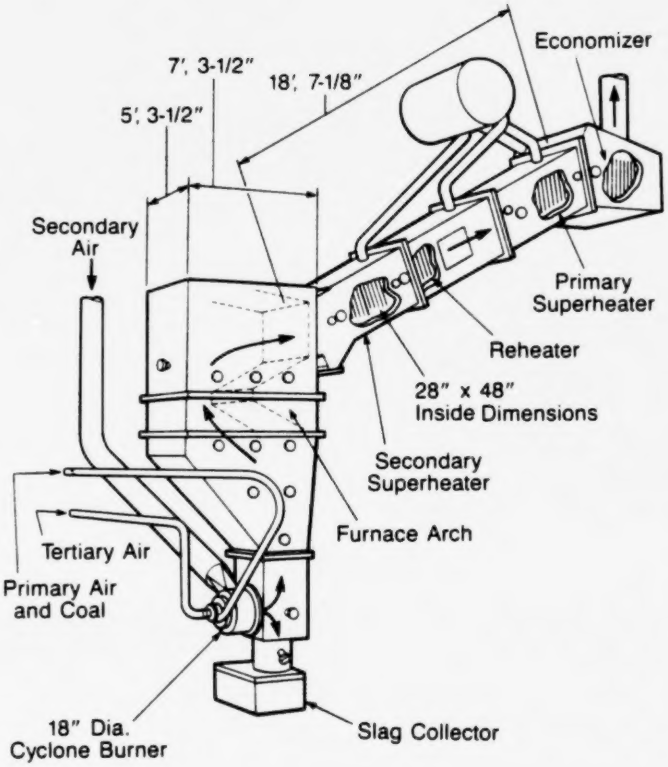

Economizer
7', 3-1/2"
18', 7-1/8"
5', 3-1/2"
Secondary Air
Primary Superheater
Reheater
28" x 48" Inside Dimensions
Secondary Superheater
Furnace Arch
Tertiary Air
Primary Air and Coal
18" Dia. Cyclone Burner
Slag Collector

Figure 7 Small boiler simulator with cyclone burner.

optimal capture results. Utilizing a Ca/S molar ratio of 2, a nominal 50% reduction was achieved.

FLUID BEDS

Atmospheric Fluidized Beds

Fluidized bed boilers can burn a variety of fuels while controlling both SO_2 and NOx below federal emission limits. Fluid beds are differentiated as either bubbling bed or circulating (fast) fluid bed, depending on fluidizing velocity (Figure 8) (8). The near term market for bubbling beds is primarily coal-fired retrofit applications for both industrial and utility boilers (Figure 9) (9,10). The driving forces are to reduce fuel costs (permit use of less desirable, lower cost coal), while avoiding slagging/fouling problems, and emission control. SO_2 is captured by calcined limestone bed material, with 90 percent capture capability with proper limestone selection and bed temperature. NOx is controlled by low bed temperatures that discourage thermal NOx and reduce reaction rates for fuel NOx. NOx depends on the coal devolatilization rate and volatile content, excess air, bed temperature, CO and SO_2 concentrations and bed hydrodynamics. NOx emissions of 0.3 to 0.4 lb/MKB are readily achieved without resorting to staging. Unburned combustibles exceed PC values, but depend on feed system design, coal type, bed temperature, superficial gas velocity, and recycle rate.

Circulating Fluid Beds (CFB), (Figure 10), are primarily used in new industrial and cogeneration units firing coal or biomass. The CFB will usually generate lower SO_2 and NOx emissions, with lower unburned combustible than bubbling beds.

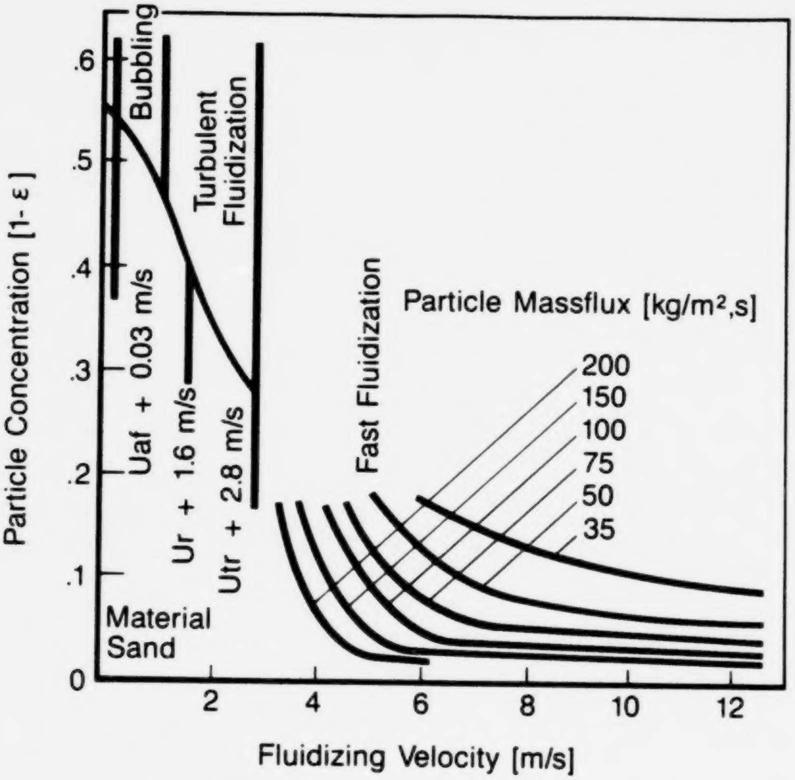


Figure 8 Fluid bed density/velocity.

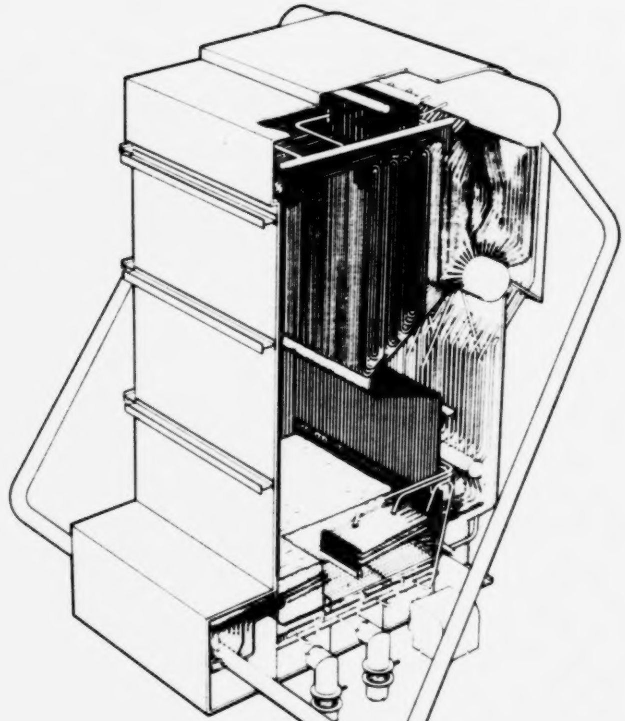


Figure 9 Bubbling bed retrofit to industrial boiler.

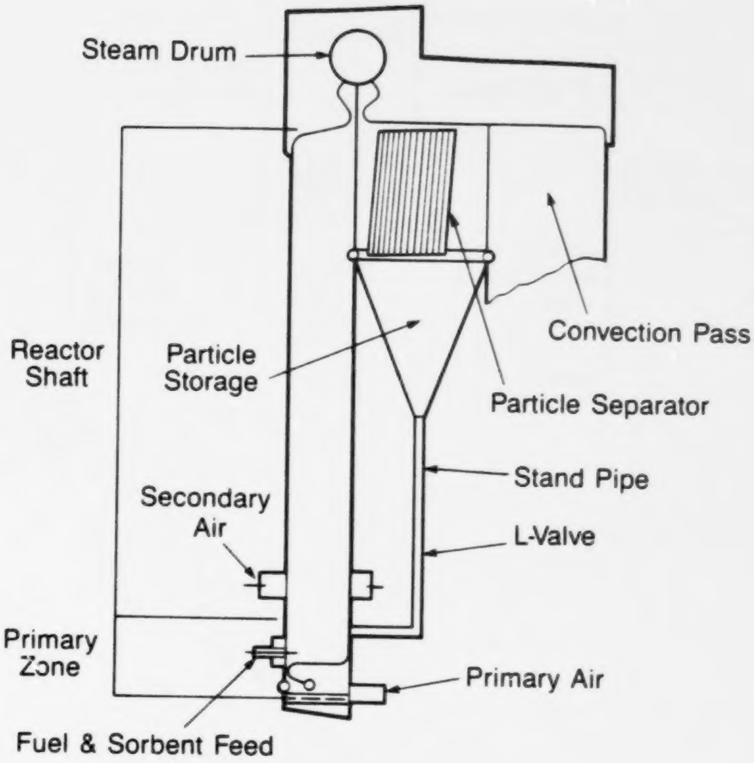


Figure 10 Circulating fluid bed.

SO_2 capture is improved by reduced sorbent particle size, such that lower Ca/S stoichiometries can be used to achieve a level of reduction. NOx is reduced by use of staging (primary/secondary air split) and low bed temperatures, to 0.3 lb/MKB typically.

Pressurized Fluid Beds

Pressurized fluid beds are expected to share attributes of atmospheric designs with respect to low SO_2 (90 percent removal) and NOx emissions (0.3 lb/MKB) with solid fuel versatility. At the same time, cycle efficiency improvements of 2 to 3 points (turbocharged system) on 4 to 5 points (combined cycle system) are expected. The technology is moving toward commercialization through a demonstration by ASEA Babcock PFBC (joint venture of Babcock & Wilcox with ASEA PFBC AB) and American Electric Power (AEP), with support expected from the State of Ohio and the Department of Energy (DOE). The demonstration involves repowering of AEP's Tidd Station with a combined cycle PFBC (Figure 11), at the 70 MW scale. The Tidd design features a single pressure vessel, an ASEA STAL two-shaft gas turbine, a high degree of modularity, a 3.5 point improvement in cycle efficiency, and utilization of the existing steam turbine and condenser (11). Negotiations with AEP and DOE have been successfully completed and await congressional approval, and negotiations with the other parties are nearing completion. Ground breaking is anticipated for later this year and start-up in late '89.

REFUSE SYSTEMS

A growing segment of industrial boilers purchased in the next 15 years will be fired by municipal refuse. Refuse systems are categorized as mass burning or

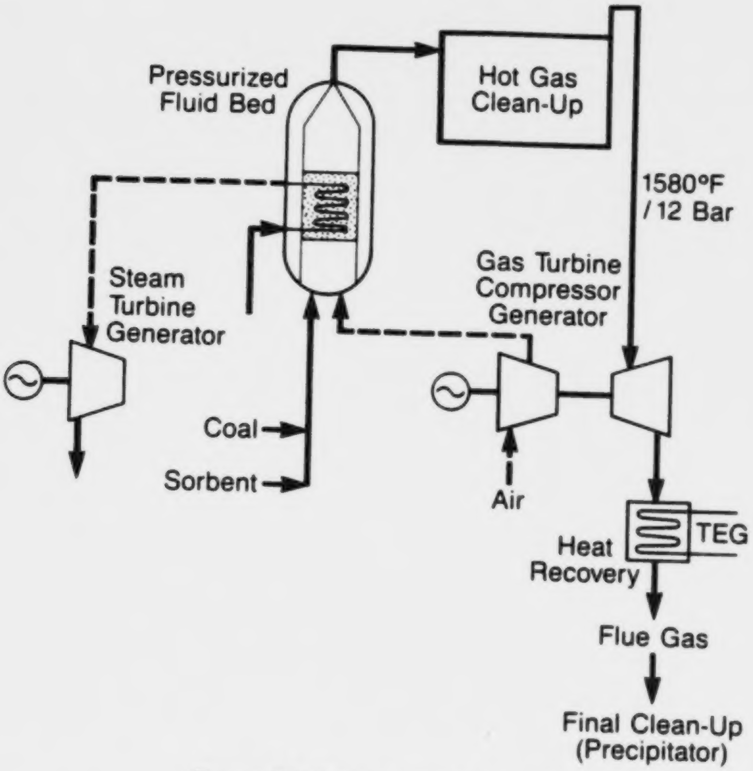


Figure 11 Pressurized fluid bed.

Refuse Derived Fuel (RDF) fired systems. Mass burning involves using refuse with minimal fuel preparation i.e. as received with large, bulkly items removed. Refuse is fed to a charging hopper and on to a reciprocating grate stoker where combustibles are burned off and ash is discharged (Figure 12). Compartmented undergrate air systems are used on modern units for even air distribution, with an overfire air system provided to improve combustion and maintain oxidizing conditions (12).

RDF is a higher grade fuel resulting from processing of municipal solid waste to remove (and/or recycle) a large portion of non-combustibles. Modern RDF preparation systems employ conveyance, size separation, shredding, material recovery (iron, aluminum), density separation, and storage. The resulting RDF heating value is significantly increased, typically from 4500 Btu/lb for municipal sold waste up to 5600 Btu/lb for RDF. The combustion system for a dedicated RDF boiler consists of overbed feeders supplying traveling grate stokers, equipped with underfire and overfire air systems. B&W has developed the Controlled Combustion Zone (CCZ^{TM}) boiler for use with RDF and biomass fuels (Figure 13). The twin arches and overfire air systems provide a major improvement to mixing and air system flexibility to handle changes in fuel quality.

Refuse-fired boilers are not subject to NSPS limits for NOx, however local restrictions (especially in non-attainment areas) are usually encountered. Concerns about pollutants such as dioxins and furans has led to a strategy of optimizing combustion conditions to minimize their formation, there being a strong correlation between low CO production and corresponding low dioxin and furan emissions. In the case of mass-fired refuse boilers, however, optimizing the combustion system for low CO has led to a slight increase in NOx emissions. In the case of RDF-fired boilers, the B&W CCZ design RDF-fired boiler is expected to optimize the combustion system for low CO, and hence low dioxin and furans, while

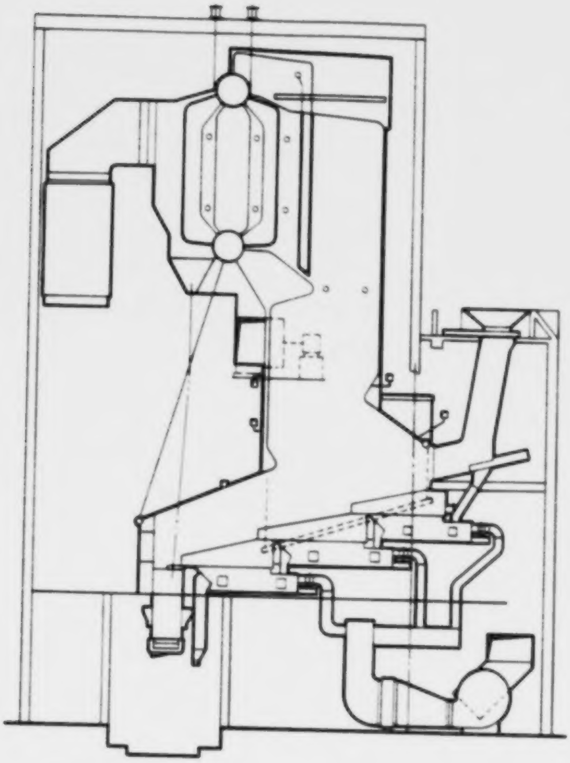


Figure 12 Mass burning refuse boiler.

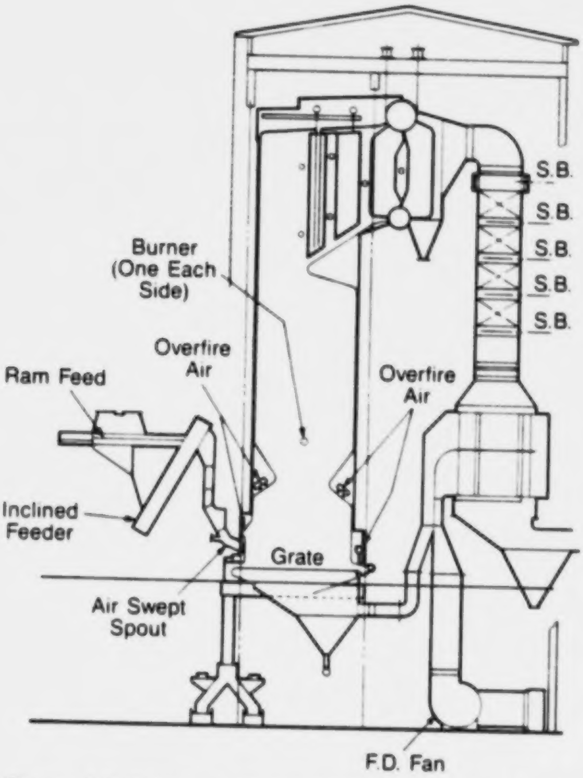

S.B.
S.B.
S.B.
S.B.
S.B.
Burner (One Each Side)
Overfire Air
Ram Feed
Overfire Air
Inclined Feeder
Grate
Air Swept Spout
F.D. Fan

Figure 13 State-of-the-art CCZ™ RDF boiler design.

also lowering excess air requirements resulting in slightly lower NOx emissions. The first such CCZ RDF-fired boilers are currently in start-up and will be tested this summer to confirm CO and NOx emissions. These emissions are expected to be low as has been the case with operating waste wood-fired units of this design. However, even lower NOx levels may be required to meet site specific requirements and, in those cases, such technologies as fluid bed combustion and/or ammonia injection systems may be employed.

LIQUID AND GASEOUS FUELS

Fuel oils remain as the major liquid fuels for utility and industrial boilers. Federal standards limit NOx emissions to 0.3 lb/MKB for liquid fuels except shale oil and coal-derived liquids. Stricter state standards have been proposed in the 0.13 to 0.20 lb/MKB range (depending on oil grade), and these limits are expected to become common in the future. NOx emissions from fuel oil combustion are a consequence of both thermal, fuel, and prompt NOx contributions. Control measures for thermal NOx obviously are directed at reducing flame temperatures, using such methods as gas recirculation, reduced air preheat, and increased combustion zone cooling surface (enlarged burner zone). Fuel NOx emissions are directly related to the percent nitrogen in the fuel oil. Control measures for fuel NOx are primarily directed at reducing oxygen availability to the fuel during devolatilization, using low NOx burners, two stage combustion, and gas recirculation. Prompt NOx, a consequence of intermediate hydrocarbon reactions with atmospheric nitrogen, contribute to a lesser degree and are controlled by reduced temperatures and reduced oxygen availability.

Natural gas is the predominant gaseous fuel for utility and many industrial boilers, recognizing that LPG, BFG/COG, propane, producer gas, etc. find significant use in some industrial applications. Federal standards limit NOx to 0.2 lb/MKB for gaseous fuels (except coal-derived gas), but again state and local restrictions are moving toward stricter limits, i.e. about 0.1 lb/MKB. NOx emissions from most gaseous fuels are a consequence of thermal and prompt NOx. Control measures repeat those listed for liquid fuel NOx control for these contributors. Since control measures overlap for gaseous and liquid fuels and because many applications require cofiring capability of gas and oil, the low NOx combustion systems which follow are suitable for either fuel.

NOx emissions are minimized by the combined usage of low NOx burners, staging, and gas recirculation, in a properly sized and arranged combustion zone. The Primary Gas-Dual Register Burner (PG-DRB), developed by Babcock Hitachi K. K. with B&W DRB technology, is designed for new or retrofit applications firing gas and oil (Figure 14). This dual register burner includes a primary gas (PG) annulus that surrounds the core zone housing the oil atomizer. The PG annulus is directly supplied with recirculated flue gas which serves to blanket the base of the oil flame to reduce oxygen availability to devolatizing oil, and reduce flame core temperatures for natural gas. Recirculated flue gas is mixed with secondary air ahead of the windbox and serves to reduce oxygen availability and peak flame temperatures. The secondary air plus flue gas is introduced through the core (or primary air) zone, secondary air zone, and tertiary air zone, in a manner which delays oxygen availability during devolatilization. NOx ports are used to direct combustion air from the primary combustion zone. Dual zone NOx ports have been developed to provide improved furnace mixing of air introduced through the ports. The ports provide for jet penetration of furnace gases for fuel mixing, and swirled air injection for near field mixing. NOx emissions of 0.2 and 0.1 lb/MKB for fuel oil and natural gas respectively, are achievable with this system in utility and industrial systems.

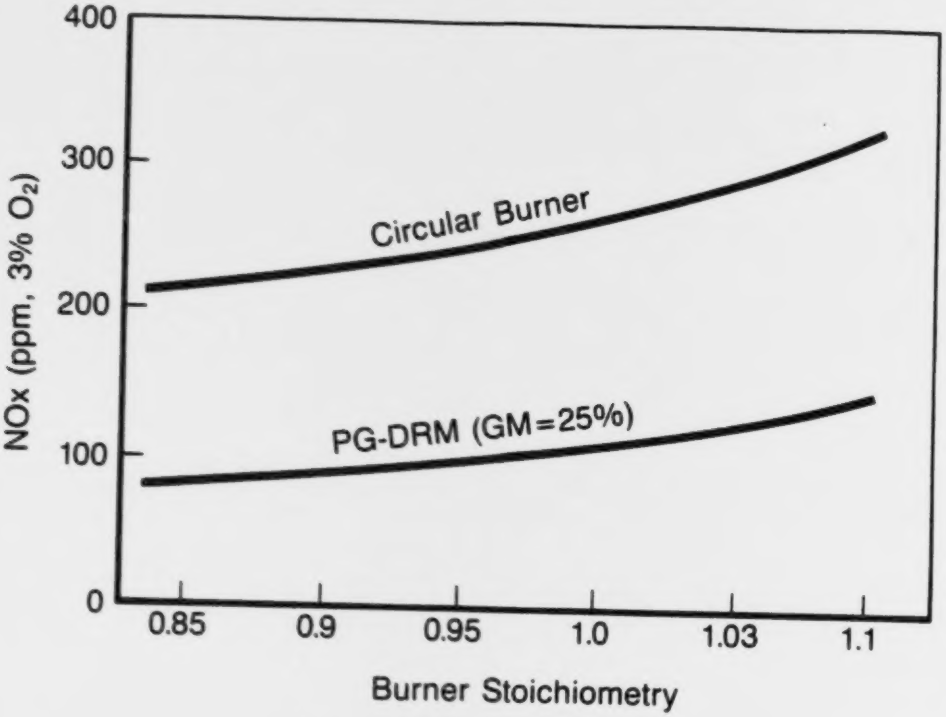


Figure 14 PG - dual register burner.

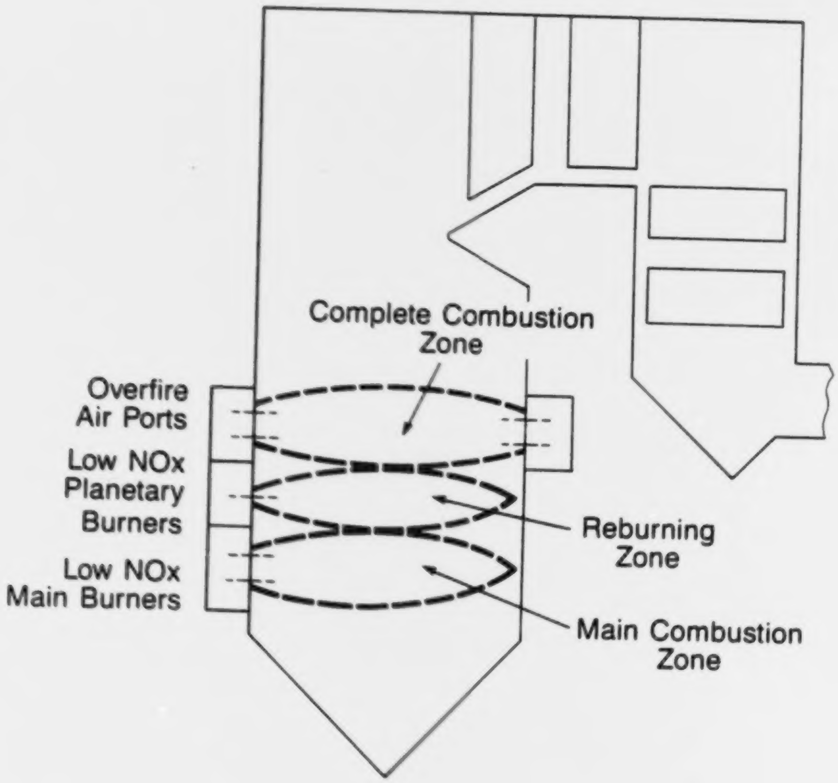

Complete Combustion Zone
Overfire Air Ports
Low NOx Planetary Burners
Low NOx Main Burners
Reburning Zone
Main Combustion Zone

Figure 15 IFNR system arrangement.

IN-FURNACE NOx REDUCTION

In-Furnace NOx Reduction (IFNR) provides the means to further reduce NOx emissions. Babcock & Wilcox has licensed rights to this reburning technology, which was developed by Babcock Hitachi and Tokyo Electric Power Company. Commercial applications in Japan operate with NOx emissions of 10-40 ppm with natural gas and 40-60 ppm on fuel oil. The IFNR combustion system, depicted in Figure 15, consists of PG-Dual Register Burners, operating below 1.0 stoichiometry in the main combustion zone, and operating at much lower stoichiometry in the reburning zone, and NOx reduction by reaction of hydrocarbon radicals with NO species in the reburning zone. Combustion is completed by air introduced through overfire air ports above the planetary burners. IFNR has residence time minimum requirements to enable NOx reduction reactions and provide for complete combustion. System configuration requirements and residence time are constraints which must be considered for new or retrofit applications.

SUMMARY

The U.S. marketplace for systems to control NOx emissions in utility and industrial boilers has changed dramatically since New Source Performance Standards were first enacted in 1971. Activity levels are reduced, while system and fuel variety have increased. NOx emissions limits for new sources are becoming more strict, while existing sources are beginning to face NOx restrictions in some locations. Babcock and Wilcox is pursuing the strategy of developing advanced combustion systems to control NOx emissions for new units, and for major categories of existing equipment which are expected to face NOx limitations in the future.

Low NOx PC burners have been developed based on extensive experience with the Dual Register Burner. The Enhanced Ignition and Primary Air Exchange burners limit NOx while firing low volatile or anthracite coals. The XCL reduces NOx further while incorporating individual burner air flow measurement to improve performance. The Adjustable Swirl Burners provides NOx control in industrial applications. Low NOx cell burners have been developed for retrofit use in the event of "acid rain" legislation. Similarly, reburning technology is being investigated as a control strategy for cyclone boilers. Fluid beds limit NOx by virtue of the combustion method and can be enhanced by staging. Refuse systems face a wide range of emission restrictions which can complicate their simultaneous control. The CCZ furnace offers potential for improved combustion with reduced excess air to limit NOx. Oil- and gas-fired units can be equipped with PG-Dual Register Burners and advanced staging systems, including In-Furnace NOx Reduction, to greatly reduce NOx emissions. Application of low NOx systems to new or existing equipment requires careful study and evaluation to ensure the intended performance objectives can be achieved compatibly with the boiler.

REFERENCES

1. LaRue, A. D., Cioffi, P. L., Acree M. A., "Utility Steam Generator NOx Control Update - 1985" presented at the Joint Symposium on Stationary Combustion NOx Control, Boston, May 1985.

2. Narita, T., et al, "Development of the Low NOx Burner for Pulverized Coal-Fired In-Furnace NOx Reduction System" presented at the Joint Symposium on Stationary Combustion NOx Control, Boston, May 1985.

3. LaRue, A. D., Acree, M. A., Masser, C., "Development Status of B&W's Second Generation Low NOx Burner - The XCL Burner" presented at the Joint Symposium on Stationary Combustion NOx Control, New Orleans, March 1987.

4. Ibid.

5. LaRue, A. D., Rodgers, L. W., "Development of Low NOx Cell Burners for Retrofit Applications" presented at the Joint Symposium on Stationary Combustion NOx Control, Boston, May 1985.

6. Clark, M. J., et al, "Large Scale Testing and Development of the B&W Low NOx Cell Program" presented at the Joint Symposium on Stationary Combustion NOx Control, New Orleans, March 1987.

7. Maringo, G. J., H. Farzan, L. W. Rodgers, and G. Offen, "Application of Upper-Furnace Sorbent Injection for SO_2 Control in Coal-Fired Cyclone-Equipped Boilers" presented at the Joint Symposium on Dry SO_2 and Simultaneous SO_2/NOx Control Technology, North Carolina, June 1986.

8. Whitney, S. A., Johnson, J. L., Hemmingsson, L., "Wood-Fired Fast Fluidized Bed Boiler" presented to Energy Technology Conference and Exposition, Washington D.C., March 1986.

9. Whitney, S. A., Smith, J. W., "Industrial Fluidized Bed Design and Operation of the TVA Test Facility" presented to the 6th International Coal and Lignite Utilization Exhibition and Conference, Houston, November 1983.

10. Whitney, S. A., et al, "Utility Fluidized Bed Operating Experience" presented to the Joint Power Generation Conference, Indianapolis, September 1983.

11. Haberman, J. A., Hansson, J. "Readiness for Demonstration of Combined Cycle PFBC" presented to EPRI Second Biennial Pressurized Fluidized Bed Combustion Power Plants Utility Conference, Milwaukee, June 1986.

12. McNertney, R. M., Chambliss, C. W., Hestle, J. T., "Operating Experience is Reflected in Nashville's New Refuse Boiler" presented to ASME/IEEE Joint Power Generation Conference, Portland, October 1986.

13. Gibbs, D. R., Kriedler, L. A., "From Hamilton to Palm Beach: The Evolution of Dedicated RDF Plants" presented to Processed Fuels & Materials Recovery from Municipal Solid Waste Symposium, Washington D.C., December 1986. BR-1294 (B&W paper).

THE FEDERAL CLEAN COAL PROGRAM

Jack S. Siegel
Deputy Assistant Secretary
for Coal Technology
U.S. Department of Energy
Washington, D.C. 20545

THE FEDERAL CLEAN COAL PROGRAM

INTRODUCTION

In a recent study,(1) "Clean Coal Technology" (CCT) was defined as a generic term encompassing a variety of techniques for reducing SO_2, NO_x, and particulates. In that study, it was observed that the technology may be designed to be retrofitted on older boilers without modification or be primarily intended for new powerplant construction; the technology may be able to achieve New Source Performance Standards for one or more pollutants or achieve a more significant reduction in pollutant emissions; the technology may be able to provide only a modest cost saving over current technology or result in a substantial saving and, finally, the technology may require several more years of development or it may be ready for demonstration now.

The Department of Energy's Clean Coal Technology Program is broader in scope than just the control or prevention of pollutants from coal using machines as the above definition implies. It also addresses the energy needs of the U.S. economy, i.e., coal technologies which can compete with oil and gas for markets which are now dominated by oil and gas; coal technologies which will allow utilities to cut the long lead times now necessary to design and construct conventional coal-fired boilers with scrubbers; and coal technologies which not only control SO_2 and NO_x to NSPS or better levels, but which also are more efficient and produce more easily disposable wastes than the conventional technologies. It is our objective to examine the scope of this effort, present an overview of the R&D activity, including the recently initiated clean coal demonstration program, and discuss the attributes of the technologies which should ensure that once demonstrated, they will be used commercially.

SCOPE OF THE PROGRAM

The Federal Clean Coal Program consists of a large number of projects encompassing a wide range of concepts for a wide variety of applications with the potential to use coal in a more efficient and cost-effective manner. These concepts include technologies that remove the impurities from coal prior to combustion, reduce or eliminate the generation of SO_x and/or NO_x during combustion, capture and remove these same pollutants as well as particulates from post-combustion gases, and convert coal to liquids and gases while removing the pollutants.

Until just recently, the Program has been principally an R&D effort aimed at the development of advanced concepts in the very early stages of development where the risks are high and the associated schedules leading to commercialization are quite lengthy. Recently, however, the research program has been supplemented with a three-phase demonstration activity. Starting with the initial Clean Coal Technology (CCT) Program Opportunity Notice that resulted in the selection of nine jointly funded projects, this effort will in 1988 and subsequent years be expanded to include projects from subsequent solicitations. These future procurements are much less developed conceptually, having just been proposed as part of the President's FY 1988 budget to the Congress and more recently as a $2.5 billion initiative to satisfy the recommendations presented in the January, 1986, Joint Report of the Special Envoys on Acid Rain.

As shown in Table 1, approximately $3.2 billion has been spent on the development of new coal technologies during the period from 1980 to 1985. Of this amount, $935 million has been spent by the Federal Government to develop innovative clean coal technologies.

The technical ground work developed in the late 1970's and early 1980's has been critical in gauging the readiness of emerging clean coal technologies for scale-up and eventual commercialization. Based upon what was learned within the last six years particularly, the nation now has the data to make much better projections of the reliability, costs and environmental performance of the new clean coal technologies now moving into the commercial demonstration phase. The progress made, in fact, provides the technological basis for proceeding with the Federal Clean Coal Demonstration Program that began in 1986.

Based upon analysis conducted by the DOE, it is estimated that the U.S. will invest in excess of $10 billion between FY 1986 and FY 1992 on the development and demonstration of clean coal technologies. As shown in Table 2, of this amount, over $4 billion will be provided by the Federal Government, while over $6 billion will come from state and private sources.

DESCRIPTION OF THE RESEARCH AND DEVELOPMENT PROGRAM

As observed earlier, the efforts of the research and development program directed towards developing advanced clean coal technologies addresses the problems of pollutant precursors and their removal and/or control at the four stages in the coal utilization cycle. Pre-combustion technologies include coal preparation and advanced coal beneficiation technologies. Combustion technologies include fluidized-bed combustors, advanced combustors, alternative fuels combustion, and limestone injection multi-stage burners. Post-combustion technologies include flue gas cleanup, gas stream cleanup and heat engines. In addition, coal conversion technologies include coal gasification and coal liquefaction. The objectives and goals of these technologies as well as some of the major projects are discussed below.

PRE-COMBUSTION SYSTEMS

Coal Preparation

The goal of the coal preparation program is to develop coal cleaning technologies to reduce the ash and sulfur content of U.S. coals. The product can be formulated into a high-quality fuel that

TABLE 1

Coal Technology R&D Funding

1981-1985 R&D FUNDS ($ in millions)

TECHNOLOGY	TOTAL	DOE/FE	EPRI	EPA	TVA	GRI	ASSOC.	STATES	PRIVATE COFUNDING
Fuel and Feedstock Producing Technologies	229.230		229.230						
- Coal Preparation	88.806	66.729			3.994			3.974	13.796
- Coal Mixtures/Alt. Fuels	37.728	27.343					0.730	9.034	0.743
- Liquefaction	781.340	*303.108						8.000	470.232
- Surface Gasification	479.533	233.069				40.600	0.113	2.879	212.972
- Underground Gasification	45.843	35.533				4.600	0.768		5.043
Power and Energy Producing Technologies	239.625		239.625						
- Atmospheric Fluidized Bed Combustors	155.428	31.069			82.610		1.254	4.083	46.312
- Pressurized Fluidized Bed Combustors	85.121	69.260							15.861
- Fuel Cells	308.903	179.308			0.178	63.300	0.653		65.463
- Magnetohydrodynamics	184.874	177.961							6.913
- Heat Engines	76.105	67.469					0.343		8.383
Environmental Pollution Reduction Technologies									
- Flue Gas Cleanup	137.956	50.477		19.000	34.834		19.737	2.376	31.543
- Gas Stream Cleanup	97.294	45.831		40.300			0.203	0.936	0.913
- Advanced Combustors	16.607	7.733			0.200		0.499	1.187	6.988
Cross-Cutting R&D									
- Coal Waste Management	37.879	19.134			1.884	1.700		0.533	14.629
- Advanced Research & Technology Development	306.419	213.744				4.900	0.803	5.115	82.057
Subtotals									
- Clean Coal R&D	1659.364	798.583	239.625	59.300	113.512	42.200	23.078	25.003	358.063
- Other Coal**	1618.997	678.175	229.230	0	0.178	72.600	3.033	14.014	622.797
TOTAL	3278.371	1476.758	468.845	59.300	113.690	114.800	26.101	39.017	980.860

* Does not include Solvent Refined Coal Demonstration Projects

** Includes Liquefaction, Underground Gasification, Fuel Cells and elements of Adv. Res & Tech Develop

Reproduced from best available copy.

Planned Innovative Clean Coal Technology R&D and Demonstrations ($ in Millions)

CATEGORY			FEDERAL	STATE	EPRI	PRIVATE	TOTAL	FY	REMARKS
FEDERAL	Federal Control Tech. R&D								
	DOE		738				738	86-92	Budget Projections
	EPA		21			7	28	86-92	Budget Projections
		Subtotal	759			7	766		
	Federal Demonstrations								
	DOE Clean Coal Prog-1		396	39		560	995	86-88	Projects in negotiations
	DOE Clean Coal Prog-2		850			850	1700	88-89	Estimated as 50% co-funding
	DOE Clean Coal (Remainder)		1500			1500	3000	90-92	Estimated as 50% co-funding
	Other DOE Supported Projects		14	4		1	19	91-92	Kilngas & Commonwealth Edison
	Environ. Protection Agency Projects		5			12	17	86-92	Tangentially Fired LIMB
	Dept. of Treasury Projects		480*	2	105	600	1187	86-92	DOW Syngas & Cool Water
	Tennessee Valley Authority Projects		67	10	81	82	240	86-92	160 MW AFBC, 20 MW AFBC & Spray Dryer/ESP
		Subtotal	3312	55	186	3605	7158		
		Federal Total	4071	55	186	3612	7924		
NONFEDERAL	State-Financed Clean Coal Projects	Subtotal		253		124**	377	86-92	Illinois & Ohio Only
	Private Demonstrations								
	EPRI Privately Financed Projects				79	287	366	86-89	Five Projects
	Other Privately Financed Projects					1338	1338	86-92	
		Subtotal			79	1625	1704		
	Private Research & Development								
	EPRI R&D				103		103	86-89	
	GRI R&D					40	40	86-89	
		Subtotal			103	40	143		
		Nonfederal Total		253	182	1789	2224		
SUMMARY	Total U.S.		4071	308	368	5401	10148		

*Represents price guarantees to be paid out
**Co-funding not fully determined

Table 2

could replace oil and/or natural gas and reduce environmental emissions in both new and retrofit applications in utility boilers, industrial boilers and process heaters, residential/commercial boilers and furnaces, and heat engines such as gas turbines and diesel engines.

Most coals resist cleaning by conventional practices either because the ash and sulfur constituents are too finely dispersed in the coal structure or because the organic sulfur content, which does not respond to physical cleaning, is too high. Low-rank coals and lignites are handicapped by excessive moisture contents and unfavorable ash characteristics. The principal thrust of the coal preparation program is thus directed toward: new and advanced cost-effective technologies to clean and condition finely comminuted (ground) coal as necessary to liberate finely dispersed pyritic sulfur and ash particles; and advanced experimental methods to extract organic sulfur from coal.

The current program encompasses laboratory and bench-scale research efforts focused on the removal of finely dispersed mineral matter impurities, pyritic sulfur, and organic sulfur from all coals. The program includes research on physical and chemical beneficiation techniques and supporting research such as micro-characterization, efficient grinding, on-line analysis, and dewatering.

In the physical cleaning area, selective coalescence, froth flotation, and specific gravity techniques that have demonstrated the ability to remove 90% of the pyritic sulfur from selected coals, are being developed. Current projects include testing several advanced physical cleaning processes as part of a cooperative effort with the Electric Power Research Institute (EPRI) at the Homer City, PA, Coal Cleaning Test Facility.

Novel, efficient grinding technologies such as ultrasonics that have demonstrated the potential for significantly reduced energy requirements are being investigated. Instrumentation methods such as scanning electron microscopy and image analysis are being utilized for characterizing the finely ground raw coal and cleaned products so as to develop the basic data needed for the various cleaning technologies.

In the chemical cleaning area, the gravimelt process will undergo integrated testing at a 20 lb/hr scale to determine if program goals of 90%+ of total sulfur removal and 95%+ ash removal at reasonable costs can be achieved. We will also complete an authoritative study to fully determine, at laboratory scale, the feasibility of highly experimental biotechnology (i.e., micro-organisms) for organic sulfur removal from coal.

The cleaned coal products thus developed will become feedstock for activities in other advanced combustion systems and heat engines aimed at the conversion of existing utility and industrial units from oil or gas to coal, for new units fired either conventionally or by coal slurries, for direct firing of coal in power conversion equipment (e.g., gas turbines and diesels), for export steam coal, and for utilization in existing coal-fired boilers as a cost-effective means of reducing emissions of suspected acid rain precursors.

COMBUSTION SYSTEMS

Atmospheric Fluidized-Bed Combustion

A fluidized bed combustor is a furnace in which a bed of solid particles is suspended in a stream of up-flowing air. The suspended particles behave like a fluid. During combustion, tubes with flowing water that are located within the bed and/or above the bed in the flue gas path are heated to form steam. The steam generated is then sent to a steam turbine for the generation of electricity. The distinctive aspect of a fluidized bed combustor is that when coal and a sorbent -- such as limestone -- are injected into the bed, sulfur dioxide is absorbed by the sorbent to produce a dry and benign solid. Atmospheric Fluidized Bed Combustion (AFBC) operates at or near atmospheric pressure.

The atmospheric fluidized bed combustion technology has many attributes, including:

- There are no special coal handling requirements other than the addition of limestone to the coal feed.
- The flue gases require only particulate removal.
- The fluid-like motion of the solids in the combustion chamber promotes turbulent mixing that improves combustion efficiency and the capture of sulfur dioxide.
- The superior mixing also permits combustion at substantially lower and more evenly distributed temperatures, thus reducing formation of nitrogen oxides.
- Combustion occurs at temperatures below the ash melting point so that solids accumulation and boiler tube erosion and corrosion are minimized.
- Since it is relatively non-sensitive to feedstock, all types of coals or coal wastes can be used.
- The waste generated is a dry, benign solid that can be disposed of easily or usefully employed (e.g., as material for road or building construction).

In addition, AFBC can be used for repowering of existing coal-fired boilers to extend plant life, increase power output and reduce emissions.

The focus of the atmospheric fluidized-bed combustion (AFBC) program is to investigate innovative fluidized-bed combustion (FBC) technologies designed to reduce capital and operating costs over conventional AFBC systems. In past years, research and development efforts on AFBC have resulted in the demonstration of this technology for large industrial applications on a variety of fuels including anthracite culm. Current demonstration efforts have been concluded while the advanced AFBC program is pursuing innovative designs for improved economic competitiveness for smaller boiler sizes, performance, and environmental considerations. Special applications of atmospheric fluidized-bed combustors are being investigated for residential/commercial applications.

Awards for seven studies of advanced AFBC concepts that have the potential for 20% reduction in FBC costs and could therefore make them compatible in the small industrial boiler market, were made in April 1982. The concept studies have been completed and final reports received. The DOE awarded studies to the most promising concepts in late fiscal year 1984 in order to determine their economic potential prior to bench-scale testing. In FY 1985, these studies were completed and bench-scale testing was initiated. Special application studies and investigation of advanced AFBC concepts were also continued. In addition, Congress appropriated $30 million in FY 1984 to be allocated in FY 1985 and FY 1986 to support Tennessee Valley Authority/Electric Power Research Institute (TVA/EPRI) test plans and operational activities at the TVA/EPRI 160-MWe utility demonstration project.

Currently the program is supporting test plans and operational activities of the TVA/EPRI demonstration project; bench-scale testing of advanced concepts; continued efforts in the area of erosion mechanics, economic evaluations, fuel feeding, and residential/commercial applications; and continued support to in-house research and data evaluation.

Pressurized Fluidized-Bed Combustion

Pressurized fluidized bed combustion (PFBC) utilizes a furnace in which a bed of coal and limestone (sorbent) is suspended in a stream of upward flowing pressurized air. The suspended particles behave like a fluid. During combustion, tubes with flowing water that are located within the bed are heated to form steam. The steam generated is then sent to a steam turbine for the generation of electricity. Increased system efficiency is realized by combined cycle operation through the incorporation of a gas turbine to recover additional energy from the pressurized products of combustion. A distinctive aspect of fluidized bed combustion is that when coal and a sorbent are injected into the bed, SO_2 reacts with the sorbent to produce a dry and benign solid.

The pressurized fluidized bed combustion technology has many attributes, including:

- There are no special coal handling requirements other than the addition of limestone to the coal feed.
- Gases require hot particulate cleanup before entering the gas turbine. No flue gas cleanup is required.

- The fluid-like motion of the solids in the combustion chamber promotes turbulent mixing that improves combustion efficiency and the in situ capture of sulfur dioxide, eliminating the need for add-on removal units.

- The superior mixing also permits combustion at substantially lower and more evenly distributed temperatures. This results in the reduced formation of nitrogen oxides.

- Elevated pressures permit higher combustion intensity and reduce the size of the unit.

- Combined cycle plants, in addition to increasing the efficiency of energy production, can be composed of standardized modules. This leads to ease of installation and a relatively lower cost without the usual economy of scale penalties.

- Modularity provides for staged construction which permits smaller increments of capacity, thereby shortening construction time and lowering financing requirements.

- The space required for PFBC expansion is of the same order of magnitude as would be required for a flue gas scrubber.

- Combustion occurs at temperatures below the ash melting point so that solids accumulation and boiler tube erosion and corrosion are minimized.

- Since it is relatively non-sensitive to feedstock, all types of coals or coal wastes can be used.

- The waste generated is a dry, benign solid that can be disposed of easily or usefully employed (e.g., as material for road or building construction).

In addition, PFBC can be used for repowering of existing coal-fired boilers to extend plant life, increase power plant output and reduce emissions.

The objective of the current pressurized fluidized-bed combustion (PFBC) program is to develop PFBC systems that achieve high combustion efficiency and acceptable component durability and reliability and which operates within acceptable emission levels. The goal of DOE-sponsored activities is to develop a U.S. technology base for PFBC scientific and engineering technology data through proof-of-concept and to provide basic research in support of private sector efforts to commercialize the technology.

In FY 1985, data dissemination to industry from the International Energy Agency/Grimethorpe operations was completed and follow-up research has been negotiated to support commercialization of early steam-cooled PFBC cycles. Research activities have continued to investigate combustion characterization and alternative combustor heat exchanger configuration(s). These activities are part of a continuing effort to conduct engineering analyses and develop the PFBC data base to expedite technology transfer and use of research data.

Since tube bundle erosion is a major technical problem encountered in PFBC systems, the DOE has continued funding metal wastage investigations to verify the mechanisms and kinetics of coal/sorbent combustion products, particle energies, and materials survivability in a PFBC environment.

A cost-shared program was initiated with Foster Wheeler Corp. to develop a second generation PFBC system which would have an efficiency approaching 45% and cost of electricity reductions of 20% below conventional pulverized coal-fired boilers with flue-gas desulfurization.

Finally, key PFBC process components are being tested to expedite the availability of the technology data base to the private sector. Key components must be proven reliable and operable at a sufficient scale before the conservative U.S. utilities will proceed with privately funded demonstration project(s).

Advanced Combustion Technology

The objective of the advanced combustion technology effort is to develop the equipment to retrofit existing industrial and utility boilers designed for oil and gas firing to burn coal or coal-water mixtures (CWMs). Innovative concepts that will extend the use of coal to light industrial, commercial and residential applications are the principal focus of the program. These research efforts will be applicable as well to the retrofit of advanced combustors to existing coal-fired boilers as a means of low cost SO_2 and NO_x pollution control.

The development and testing of two slagging combustor concepts to enhance the utilization of coal as a boiler/heater fuel in large industrial and utility applications is completed. These combustors are now being offered commercially by several vendors. The DOE is now developing a number of innovative concepts that promise improvements beyond those attainable with slagging concepts, such as pulsed combustion, explosive communition, and the wet oxidation of coal.

Funds are being used in the continued development of the most promising concepts for industrial applications as well as the selection and testing of advanced combustors that have specific applicability to the commercial and residential markets.

Alternative Fuels

The objective of the alternative fuels activity is to develop the technology necessary to establish a technology base for retrofitting coal-liquid mixtures (CLMs) to existing oil- and gas-designed facilities with emphasis on coal in slurry form.

In this effort, the combustion and component characterization for CWMs in utility and large industrial boiler applications have been completed. Studies were also initiated to define specific system configurations and component requirements for small industrial/commercial/institutional applications and residential systems for CLMs using finely ground and cleaned coals. In addition, studies were completed on preliminary technical, economic, and environmental assessments for both diesel and gas turbine applications of CLM fuels.

The DOE has initiated R&D on generic combustion characterization for finely ground and cleaned coal-liquid mixtures in small industrial, residential, commercial, and institutional boiler/furnace systems. Specific R&D and assessment efforts included: analysis of fuel metering, atomization, and combustion phenomena as they affect combustion system hardware design requirements; experiments on emissions characterization; and analysis of the effects of fuel particle size, size distribution, and ash chemistry in atmospheric and various pressurized regimes on all system elements.

POST-COMBUSTION TECHNIQUES

Heat Engines

In the post-combustion part of the program, new heat engines are being researched. The heat engines program is directed toward major engineering design, durability, and performance problems associated with the substitution of coal or coal-derived fuels for distillate fuels and natural gas in firing gas turbine and diesel power conversion systems. Fuel substitution creates technical problems in both types of engines. In turbines, the durability of major components (i.e., combustors, transition ducts, and turbine airfoils) is of concern. Similarly, the hostile environments created by firing coal-based fuels affect the durability of diesel engine components, particularly cylinder walls, pistons, valves, and injectors. In addition, both applications require adjustment of combustion component design and conditions to suppress NO_x emissions and to ensure efficient combustion of the coal-based fuel.

The coal-fired gas turbine portion of the program is focused on resolving these problems as they occur in the direct firing of coal-based fuels (i.e., gasification fuel gases as well as direct fired, highly beneficiated coal feedstocks) in a gas turbine engine. The technology base to be established begins with laboratory investigations to determine the products of combustion that will traverse the power turbine section when coal-based, solids-containing fuels are used. This will be supplemented by tests of slurried fuels in gas turbine devices to solve basic problems associated with the combustion characteristics, ash deposition, corrosion, and erosion effects for specific fuels. Contracts have been awarded to four companies to conduct cost-shared research which will culminate in fully integrated proof-of-concept testing of coal-based turbine systems for industrial, transportation and utility applications.

The coal-fired diesel engine portion of the program is directed towards the use of a coal-based fuel directly in a diesel engine. Emphasis is on coal-derived gaseous fuels as well as micronized coal slurries. The current program concentrates on analytical studies and preliminary laboratory tests to correlate wear under a limited range of engine design and operating conditions and integrated testing of coal-fired turbines and diesels for a variety of applications.

Gas Stream Cleanup

The objective of this program is to identify and develop technologies to control and remove pre-combustion and post-combustion contaminants from gas streams to protect downstream components in the emerging energy conversion processes. Because of the importance of environmental concerns, the program also addresses those contaminants that have emission limits set by environmental regulations. Research and development efforts are specifically directed toward gas stream cleanup at the high temperatures (>1000°F) and pressures (>6 atm) associated with emerging energy technologies; PFBC combined-cycle systems; coal gasification combined-cycle systems; gasification/molten carbonate fuel cell systems; and direct coal-fired turbine power systems.

For PFBC technology, emphasis is on the control of post-combustion contaminants alkalis and particulates found in gas streams of the combustor/gas turbine combined-cycle power system. The combustor technology has demonstrated the capability to meet U.S. New Source Air Pollution Standards for NO_x and SO_x. However, the power turbines are subject to corrosion, erosion, and deposition caused by alkali sulfate compounds, high-velocity particles, and fine particle build-up, respectively. Since the gas turbine operates on sensible heat from the gas stream, it is essential that cleanup be accomplished at or near the 1650°F combustor temperature. At present, there are no commercially available processes to remove the particulate material or the alkali vapor under the conditions existing in the PFBC gas stream.

Precombustion contaminant control is directed at those emerging energy technologies that are based on coal gasification. These include turbine-based systems in which the coal gas is burned to generate power, and fuel cell-based systems in which the power is generated from the electrochemical potential contained in the coal gas. The contaminants of concern in the turbine-based systems are particulates and alkali. SO_x and NO_x also have to be dealt with to make the systems environmentally acceptable. For fuel cell applications the control of sulfur is of critical importance because the internal components of the device are highly susceptible to sulfidation that can lead to cell failure. In addition, other contaminants such as chlorides and particulates may have to be controlled to prevent cell destruction. As in the case of PFBC, there are no commercially available processes to remove these contaminants from the gasifier product stream at temperatures and pressures encountered in the gasification of coal.

Flue Gas Cleanup

The DOE's post-combustion cleanup program focuses on the development of a technology base for simple, cost-effective, and environmentally superior processes that remove pollutants from coal combustion gas streams in both utility and industrial boilers. Its intent is to help ensure that existing and projected utilization of coal can continue without adverse environmental effects. The primary pollutants of concern, as identified in the New Source Performance Standards (NSPS) for coal-fired utilities, consist of sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulates. Existing flue-gas desulfurization technology is capable of meeting sulfur removal requirements, but is very costly and in many cases merely converts an air pollution problem to a solid waste disposal problem in the form of difficult-to-handle sludges. The disposition of these sludges measurably adds to overall environmental control costs. Combustion modification can control NO_x emissions to existing standards. If these standards were to be tightened, however, an additional process would have to be added. Based on available technology, this process would most likely involve a gaseous-phase NO-destruction technique by reaction with ammonia in the presence of a catalyst. The addition of a process of this type for NO_x control would measurably contribute to the cost and complexity of the overall environmental control system. Therefore, an emphasis of the flue gas cleanup program has been on approaches to attain high levels of SO_2 and NO_x control in a more cost-effective manner, namely through the development of processes with the potential to remove both pollutants simultaneously in one step.

In order to avoid the problems and costs associated with the handling and disposal of scrubber sludges, primary consideration will be given to those processes that generate relatively benign or possibly usable or marketable waste products. Several key technologies under development in our program include a technique that beams electrons through combustion gases that have been treated with ammonia, converting sulfur dioxide and nitrogen oxide to dry materials that may have value as commercial fertilizers. Another concept uses copper oxide rather than lime to remove SO_x. In the laboratory, some of these processes have simultaneously captured more than 90% of the SO_2 and 60-90% of the NO_x at potentially low capital and operating costs.

In addition to the technology being developed for application to new construction under existing stringent requirements, there is a need for the development of low cost, retrofittable technology for the control of acid rain precursor emissions from existing plants. Four concepts are currently being tested which employ in-duct injection of sorbents for SO_2 control. In addition, DOE is conducting research on enhanced mass transfer for duct injection.

Waste Management

The goal of the waste management program is to promote the development of waste management technologies that will permit existing and advanced fossil fuel utilization processes to reduce oil and natural gas consumption while complying with environmental regulations without excessive costs.

The coal-fuel cycle produces a significant amount of waste. While the volume of residues from conventional technologies and those projected from emerging technologies pose a logistic problem, one of the most important unanswered questions centers around the degree of environmental hazard represented by these residues. The three principal questions being addressed by the waste management program are:

(1) What, if any, are the potentially hazardous materials that are contained in and released from the wastes?
(2) How are they emitted, or how do they occur?
(3) At what rate are potentially hazardous materials released?

The answer to the first question will identify those wastes that may pose a hazard, but it will not be the deciding factor. The answers to the questions of how potentially harmful emissions occur, and at what rate, are the key to predicting the environmental impact of fossil energy waste disposal and to developing control strategies. The principal thrust of the waste management program is directed toward: sampling and characterization, disposal, disposal site monitoring, soil attenuation studies, fixation/stabilization (immobilization of contaminants), and energy recovery from coal cleaning (preparation) wastes.

COAL CONVERSION SYSTEMS

Surface Coal Gasification

The coal gasification program is organized to foster the development of advanced gasifier systems for the production of: electric power, synthesis gas (for synthetic natural gas, indirect liquefaction, and chemical feedstocks), industrial fuel gas, and coproducts (simultaneous production of solids, liquids, and gases). The Integrated Gasification Combined Cycle's principal step is the coal gasification process. Projections on demand for power in the 1995-2000 time frame clearly indicate a need for clean and more efficient modular-type power plants. This technology will be commercially ready to meet this need if research and development associated with gasification and hot gas cleanup is continued. The development of an economically and environmentally attractive coal gasification system for the production of an industrial fuel gas will provide an important energy alternative to the industrial sector, which currently is the second largest major user of petroleum products after the transportation sector. Another very large market sector can be served by coal gasification systems through the generation of synthesis gas. Synthesis gas can be used to produce liquids, such as methanol, by indirect liquefaction; to produce hydrogen and carbon monoxide gases, which are required by industry in the production of other chemical products, such as ammonia; and as a gas that can be shifted and methanated to produce synthetic natural gas. The remaining part of the program is focused on those gasification systems capable of producing coproducts from coal. These coproducts are characterized as coal-derived liquids, gases and chars generated through the application of advanced processing techniques, new catalysts, advanced treatment systems, etc., to the once widely used low temperature carbonization process. The result will be an advanced gasification system for the production of economically competitive coal-derived liquid fuels, gases and char that can be used to replace petroleum-based feedstocks in many of their current applications.

Coal Liquefaction

The specific purpose of coal liquefaction is to convert a plentiful solid fuel resource (coal) into needed liquid hydrocarbon fuels. The fuel form value of coal is greatly enhanced by liquefaction and its environmental quality is also upgraded to a premium level by liquefaction processing. Furthermore, the applicability of liquid fuels derived from coal to existing, important, high-volume markets is outstanding. Depending on the detailed process selection, certain products are selectively favored or at least more efficiently and economically produced by coal liquefaction, but all major liquid fuels in use in the U.S. -- motor gasoline, home heating oil, diesel fuel, jet fuel, and distillate fuels for industrial or utility applications -- can be produced from a wide range of domestic coal resource types through coal liquefaction.

The overall goal of DOE's coal liquefaction program is to develop the technical knowledge needed by industry to bring advanced processes for the production of synthetic liquid fuels from U.S. coals into the marketplace when needed. The strategy is to pursue the most economically competitive technology while assuring environmental acceptability. Improvements in the yield and quality of liquid substitutes for natural crude oil and oil-derived fuels as well as reductions in capital and operating costs are objectives we seek. We are also interested in process flexibility, the use of innovative concepts and simplification of the liquefaction pathway.

The program is organized into three subprogram activities: indirect liquefaction; direct liquefaction; support studies/engineering evaluation. Indirect liquefaction involves coal gasification to produce synthesis gas (a mixture of $CO + H_2$) followed by the catalytic conversion of the synthesis gas to liquids. The liquefaction (or liquid synthesis) step is generally less complex from an engineering perspective than direct liquefaction, but the overall process is generally less efficient and often less selective to fuel grade liquids. Specific objectives of the DOE Indirect Liquefaction Program are: (1) to achieve more selective and economic yields of liquid fuels and (2) to achieve better utilization of coal-derived gas feedstock. The program supports research on advanced processes based on:

a. New catalysts able to utilize low hydrogen/carbon monoxide ratio syngas, thereby taking advantage of the new, efficient gasifiers now under development in the U.S.

b. New or modified catalysts with the selectivity to produce only desirable liquids either in a single stage or via chemical intermediates in a two-stage process.

c. Thermally efficient reactors with improved temperature control and heat recovery compared with reactors currently available for this type of reaction.

Two process concepts have been scaled up from laboratory scale for further development and evaluation in proof-of-concept facilities. The larger, an international project with a pilot plant located in West Germany, was completed in 1986. The plant used an advanced fluid bed reactor system to convert 100 barrels a day of methanol very efficiently to high octane gasoline. Operation has also been successfully completed in a second mode of operation to produce light olefins for conversion to diesel fuel and/or gasoline.

The second proof-of-concept involves the production of methanol from a simulated coal-derived synthesis gas. The facility which produces about 35 barrels per day of methanol using a liquid phase reactor system has operated successfully in La Porte, Texas, with the opportunity existing for further data generation to advance this technology. The remainder of the indirect liquefaction program consists of smaller scale laboratory and bench scale studies.

As the name suggests, direct liquefaction converts the complex organic chemical structures found in coal directly to liquid components by hydrogenation. This requires elevated temperatures and pressures and is almost always carried out in a liquid phase system containing powdered coal and a pasting solvent. The major potential advantages of direct liquefaction are high thermal efficiency and high liquid product yield. The principal disadvantages stem from the severe operating conditions involving coal slurries and the high degree of integration found among process steps.

Direct liquefaction advanced process development requires a sequence of activities. The technical development consists first of the appropriate batch tests, catalyst development and screening tests, and bench-scale process studies. Based on promising results, a key step in the cycle of process development involves scaleup of process studies to the proof-of-concept level (generally the process development or PDU stage). This step provides assurance that the process modification under study can be used in a technically sound process configuration and is thus available for use in private sector projects aimed at commercial utilization. At appropriate points in the R&D cycle, when sufficient new data are available, the impact of indicated improvements must be evaluated through process analysis and economic estimates. Such analyses serve as research guidance to indicate whether further work is justified and, if so, in what specific areas this work should be directed.

The proof-of-concept facility for direct liquefaction is the 6 TPD facility at Wilsonville, AL. Here several configurations of staged liquefaction have been tested. Currently a very promising close coupled catalytic process is under test there. The coprocessing of coal with residual petroleum crude oil is also under active study because of the anticipated improvements in plant throughput compared to recycle solvent processes. If this approach is found applicable to a variety of coals and residuum materials, it could reduce markedly the capital cost per unit of product from direct liquefaction. This process and several other advances are under study in laboratory and bench scale projects.

THE CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

There is probably no better example of the changing nature of the Federal Clean Coal Program than the demonstration effort recently initiated. The beginning of this program can be traced back to when the Congress directed the termination of the U.S. Synthetic Fuels Corporation in late 1984. As part of that action, it set aside $750 million from the funding originally allocated to the corporation. This funding was placed into a treasury account called the Clean Coal Technology Reserve Fund. In December of 1985, the Congress made available $400 million of these funds and directed the Department of Energy to run a formal competition under some fairly stringent guidelines specified in the Appropriations Act. For example, the act mandated that all potential markets for coal be considered to include utility, industrial, commercial, and even the residential and transportation markets. It specified also that all types of coal should be considered -- low sulfur as well as high -- and it specified that all applications be considered to include the use of new technologies for application in grassroots facilities as well as for retrofit on old plants.

As a result of this solicitation, nine projects were selected in July of 1986. These projects, along with the proposing industrial participant and the proposed location, are shown in Table 3. Since their selection, a number of activities have been in progress leading to the signing of a cooperative agreement and the start of the projects. These activities include the fact finding necessary to completely define the projects; the business arrangements required to confirm the identification and obligations of the industrial participants; the gathering of the data needed to complete the requirements of the National Environmental Policy Act (NEPA), the determination of rights to proprietary data; the evaluation of the requests for patent waivers, etc. Each of these activities is complicated since the Cooperative Agreement does not specify the terms and conditions of a government contractor project, but rather the procedures to be used in a full public/private sector partnership.

In spite of the complexity of these business arrangements, negotiations have been completed with the first two of the nine selected proposers. These are the American Electric Power Service Corporation which proposes to build and operate a 70 megawatt pressurized fluidized-bed combined cycle demonstration plant at its TIDD facility in Brilliant, Ohio, and the Coal Technology Corporation which proposes to replace a standard oil burner with an advanced coal-fired slagging combustor. Negotiations are in progress and are at various stages on the remaining seven projects. It does appear that the goals established for having cooperative agreements in place and for initiating these projects by June can be achieved.

Following immediately upon the start of this first clean coal technology effort will be a second and maybe even a third phase of the demonstration program. As part of the FY 1988 budget, the Administration has asked the Congress to appropriate the remaining $350 million in the Clean Coal Technology Reserve Fund over the next five years to finance two additional rounds of clean coal technology competition. As proposed, there will be a significant difference, however, in these solicitations. The criteria used in the selection process will be formulated as to result in the selection of technologies that are more responsive to the recommendations of the U.S. and the Canadian Special Envoys Report on Acid Rain (2). As originally planned, the first round of competition was to be funded by $50 million to be made available in FY 1988 and by another $100 million in FY 1989. This solicitation was to focus on technologies that can retrofit, repower or modernize existing facilities. As proposed in the budget, the third round was to be supported by the request for $200 million to be made available in 1990 through 1992. This third round was to provide the opportunity to continue the development of numerous technologies still in the development phase today that would not be sufficiently mature to compete in the second solicitation. However, with another two years of development, they would be ready. This phased approach provides the maximum opportunity to advance the state-of-the-art of these technologies.

The details of these two planned programs are now being revised as a result of the President's March 18, 1987, announcement that he will seek $2.5 billion in appropriations over the next five years for the demonstration of clean coal technologies.

The actual measure of the success of this demonstration activity will, of course, depend upon the degree to which the technologies achieve their development goals and are commercialized. Such factors as market demand, regulatory policies, economic competitiveness will be significant factors in their use. While the impact of these factors cannot be predicted today and, consequently, the degree of commercialization and use may be uncertain, the implementation of the demonstration program and the development of these technologies will insure that a wide range of advanced technology options will be available to the private sector. The program also will create the opportunity for a large number of the industrial members of that private sector to be involved in a financial and in a decision-making role in the development of new coal technology. The maximum opportunity will have been created for that technology to be transferred to and implemented by those industries, utilities, companies, individuals, etc.

AMERICA'S COMMITMENT TO CLEAN COAL

In summary, it can be said that the Federal Clean Coal Program represents a significant effort to resolve those problems inherent in the use of coal in an environmentally benign manner. It is a program that the Department can point to with pride. As noted recently,(3) the baseline program being proposed by the Department in FY 1988 will devote 72% of the funding to the development of technologies that can control SO_2 and NO_x either before, during, or after coal combustion.

It is important to emphasize, however, that the Federal Clean Coal Program is only a part of what is being defined as America's Clean Coal Commitment. This commitment, as defined in a recent publication,(4) "is a national effort involving the Federal Government, state governments and private sponsors. Between 1986 and 1992, the Nation will likely invest more than $6 billion to develop and demonstrate the emerging new generation of clean coal concepts." America's clean coal commitment of which the Federal Clean Coal Program is a significant part has the reported potential to:

- Control large amounts of the SO_2 and NO_x released from coal-fired powerplants including those in the environmentally-sensitive Northeast.
- Return economic benefits to American consumers by permitting clean energy to be generated without financially constraining capital investments for environmental controls.
- Retrofit and repower aging coal-fired powerplants, particularly those in the East.
- Use high-sulfur coals, thereby avoiding the social disruptions associated with massive coal switching.
- Reduce acid rain related emissions--especially from aging powerplants in the Nation's northeast quadrant.

REFERENCES

(1) Parker, Larry B. and Alvin Kaufman, "Clean Coal Technology and Acid Rain Control: Birds of a Feather?" Report No. 85-207 ENR, Congressional Research Service, The Library of the Congress, October 23, 1985.

(2) Lewis, Drew and William Davis, "Joint Report of the Special Envoys on Acid Rain," January 1986.

(3) "The FY 1988 Fossil Energy R&D Budget Request," A Statement by J. Allen Wampler, Assistant Secretary for Fossil Energy, U.S. Department of Energy, to the Subcommittee on Research, Development and Applications, Committee on Space, Science and Technology, U.S. House of Representatives, February 26, 1987.

(4) "America's Clean Coal Commitment," A Report Prepared by the Office of Fossil Energy, U.S. Department of Energy, February 1987.

TABLE 3

CLEAN COAL TECHNOLOGY PROJECTS

Proposer	Project Title	Project Location
American Electric Power Service Corp.	Tidd PFBC Demonstration Plant	Brilliant, OH
Babcock & Wilcox	LIMB Demonstration Project Extension	Lorain, OH
Coal Tech Corp.	Advanced Cyclone Combustor Demonstration	Williamsport, PA
Energy and Environmental Research Corp.	Gas Reburning/Sorbent Injection	Springfield, IL Hennepin, IL Bartonville, IL
Energy International, Inc.	UCG/Clean Fuels Proof-of-Concept Project	Rawlins, WY
General Electric Co.	Integrated Gasification - Steam Injected Gas Turbine	Evendale, OH Dunkirk, NY
The M.W. Kellogg Co.	The Appalachian Project	Cairnbrook, PA
Ohio Ontario Clean Fuels, Inc.	Prototype Coal-Petroleum Coprocessing Plant	Warren, OH
Weirton Steel Corp.	Kohle Reduction (KR) Ironmaking Demonstration Plant	Weirton, WV

DEVELOPMENT STATUS OF B&W'S SECOND GENERATION LOW NO_x BURNER--THE XCL BURNER

Albert D. LaRue
Michael A. Acree
Domestic Fossil Operations
Babcock & Wilcox
Barberton, Ohio 44203

Charles Masser
Air and Energy Engineering Research Laboratory
U. S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

ABSTRACT

Due to the national concern with acid rain, the U.S. NO_x emission standards may become more stringent for new sources, and uncontrolled sources may face NO_x emission limits. B&W has consequently proceeded to develop a second generation low NO_x pulverized coal (PC) burner suitable for new or retrofit applications. A primary objective is to minimize NO_x by burner design to avoid slagging and corrosion concerns associated with staged furnace operation. Development of the XCL burner stemmed from the technology of Babcock Hitachi's HT-NR burner design. The development program was cosponsored by the EPA, and consisted of full scale (80 million Btu/hr)* tests of a standard Dual Register burner, an HT-NR burner, and an XCL burner. Air flow tests were conducted to characterize flow patterns and improve swirl efficiency, and combustion tests were performed to evaluate and minimize emissions. The XCL burner proved capable of NO_x emissions (unstaged) of 0.3 to 0.5 lb/million Btu with high efficiency and adjustable flame shape.

Consequently, a full complement of XCL burners was retrofitted to Ohio Edison's Edgewater Unit 4 for the EPA Limestone Injection Multistage Burner (LIMB) demonstration. The paper describes development and field results with the XCL burner.

INTRODUCTION

In the U.S., several factors have caused a need for combustion equipment capable of lower NO_x emissions. Federal New Source Performance Standards (NSPS) for NO_x emissions from pulverized-coal-fired boilers are under review and may become more stringent in the years ahead. Since their enactment in 1971, the emissions limits have been reduced once. Also, areas of the country designated as

---

* Readers more familiar with metric units may use the conversion factors listed at the end of this paper.

Non-Attainment (i.e., not meeting National Ambient Air Quality Standards) require emission offsets for new sources. This requires the new source to be equipped with combustion systems capable of extremely low NO_x emission levels, usually backed up by expensive Selective Catalytic Reduction (SCR) gas cleanup systems. Even in attainment areas, Prevention of Significant Deterioration (PSD) reviews can result in NO_x emission limitations well below federal standards for a specific new source. Lastly, NO_x emissions from existing sources have been regulated in some states, and the possibility exists of regulation on a federal basis.

It will often be more difficult to achieve a specified level of emission (e.g., NSPS limits) in an existing source compared to a new source. Many existing sources have compact combustion zones that contribute to thermal NO_x generation and limit flexibility in arrangement of low NO_x equipment. Consequently, the combustion system requires enhancements to satisfy emission limits. In any case, the combustion system is expected to control NO_x emissions while efficiently burning the coal; i.e., with low levels of CO and unburned combustibles.

One of the most effective means of augmenting present day low NO_x burners is the use of two stage combustion. Reducing combustion zone stoichiometry to 1.0 and below is a proven means to sharply lower NO_x emissions. However, many boilers have experienced extensive furnace tubewall wastage as a result of operating at reduced stoichiometry, particularly when burning eastern U.S. coals with 2 to 3% sulfur or more. The tube damage is attributed to H_2S and FeS attacking carbon steel tubes in a reducing environment (1). Further, the higher iron contents in the ash of eastern coals contribute to ash fusion temperatures hundreds of degrees lower for reducing conditions. This leads to wet or plastic slag deposits forming in the combustion zone during two stage operation and associated operating problems with uncontrolled slagging. Consequently, two stage operation is not well suited for many eastern coals.

A better solution is a burner capable of very low NO_x emission levels in normal conditions. Such a burner should be capable of reducing NO_x emissions well below present designs without resorting to two stage combustion with NO_x ports. Eliminating NO_x ports would avoid the combustion zone slagging and corrosion problems, while reducing costs and operating complexities. In addition, the problems of locating, feeding, and controlling the ports in retrofit applications would be avoided.

These factors led Babcock & Wilcox to initiate a program to develop a second generation low NO_x burner.

BACKGROUND

The most promising combustion technologies to further reduce NO_x emissions were involved with controlling fuel nitrogen conversion to NO_x during devolatilization. Previous work (2,3) had shown the majority of NO_x formed in PC combustion, 75 to 90%, was contributed by oxidizing nitrogen bound to the fuel molecules. Further, the fuel nitrogen evolved during devolatilization had the greatest contribution to overall NO_x. The effectiveness of present day low NO_x burners, such as B&W's Dual Register burner (Figure 1), depends on this principle. The Dual Register burner (DRB) introduces fuel to the combustion zone as an axial fuel jet, with which secondary air gradually mixes as combustion proceeds into the furnace. Although all of the combustion air is introduced through the burner, the stoichiometry apparent to the fuel drops rapidly as O_2 from the primary air (transporting the coal) is consumed and O_2 from secondary air is gradually introduced. The low apparent stoichiometry occurs during devolatilization and produces competing reactions for volatile nitrogen which result in formation of N_2 rather than NO or NO_2.

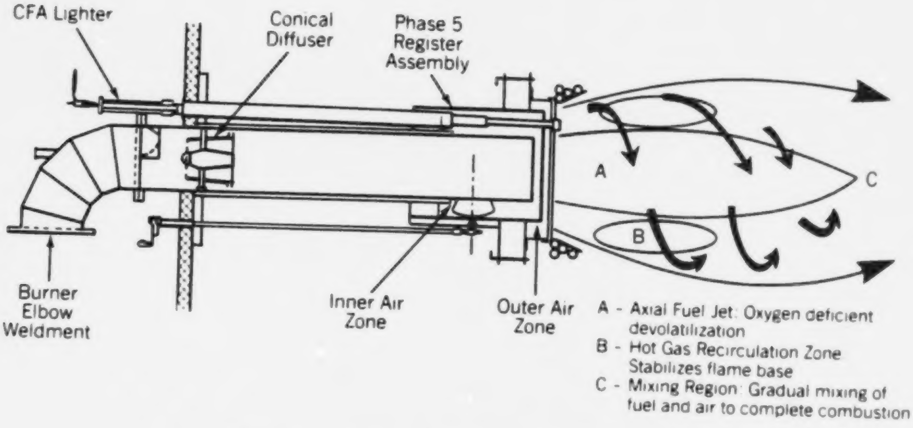

CFA Lighter
Conical Diffuser
Phase 5 Register Assembly
A
B
C
Burner Elbow Weldment
Inner Air Zone
Outer Air Zone
A - Axial Fuel Jet: Oxygen deficient devolatilization
B - Hot Gas Recirculation Zone Stabilizes flame base
C - Mixing Region: Gradual mixing of fuel and air to complete combustion

Figure 1 Phase 5 Dual Register Burner.

Recent developments by Babcock Hitachi K.K. (BHK) in the Hitachi NO_x Reduction (HT-NR) burner have advanced the potential of ultralow NO_x emissions from combustion of pulverized coal. The HT-NR burner technology is available to B&W through the In-Furnace NO_x Reduction license from BHK to B&W. The HT-NR burner (Figure 2) was reported in the Joint NO_x Symposium in Boston (4) and subsequently has achieved NO_x reductions of 30 to 50% relative to BHK's Dual Register burner performance, and up to 80% reduction relative to uncontrolled emission levels from circular burners. The HT-NR burner accelerates the combustion rate during devolatilization. Pulverized coal leaving the axial fuel nozzle is rapidly

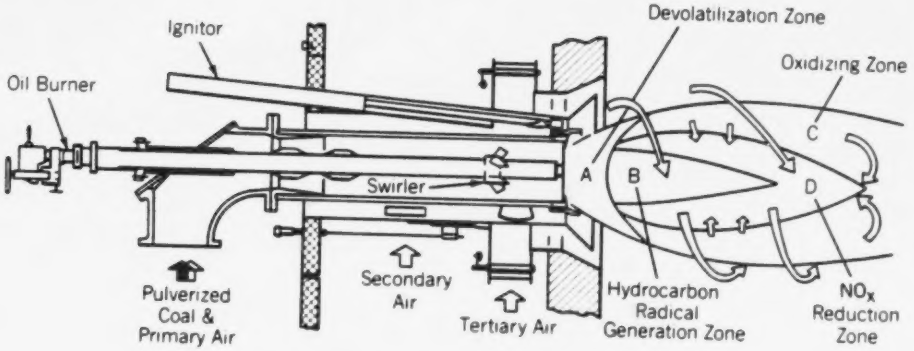

Ignitor
Oil Burner
Devolatilization Zone
Oxidizing Zone
A
B
C
D
Swirler
Pulverized Coal & Primary Air
Secondary Air
Tertiary Air
Hydrocarbon Radical Generation Zone
NO_x Reduction Zone

Figure 2 Hitachi-NO_x Reduction Burner.

ignited by virtue of recirculation patterns set up by the Flame Stabilizing Ring at the nozzle exit, yet done so at low stoichiometry. Hydrocarbon radicals and intermediate nitrogenous species, formed immediately downstream of the ignition zone in a fuel rich area, reduce NO formed during devolatilization. As the flame continues forward, highly swirled secondary air re-enters the flame core downstream to complete combustion. The combination of the Air Separation Sleeve with highly swirled secondary air throws the air away from the flame during the critical devolatilization and NO_x reduction stages, and subsequently returns the air rapidly to the flame downstream allowing char reactions to proceed rapidly. This rapid reintroduction of secondary air downstream limits flame length, as set by final char reactions.

METHODOLOGY

The proven NO_x reduction capability of the HT-NR burner (reported upon further in this symposium) became a fundamental part of the program described here. In addition, several other features appeared desirable for inclusion in a second generation burner for its use in the U.S. First, many older wall-fired boilers, which may eventually need such a burner, experience problems with secondary air flow distribution. On modern units, B&W uses the compartmented windbox (Figure 3) to measure and control air flow to the burners served by each pulverizer. Older units, often not arranged to permit compartmentation, experience wide variations in air flow horizontally and vertically in the windbox. Consequently, a need exists for individual burner air flow measurement to facilitate secondary air distribution in these units. Second, mechanical performance has suffered on many burner designs due to the hot, dusty environment in which they operate. Burners experience high thermal gradients and cycling as they cycle in and out of service and this can result in components overheating or locking up. B&W's S-type burner, developed a few years ago to alleviate these problems, incorporates air measurements capability. The second generation low NO_x burner would be configured to include these features. The importance of secondary-air-flow peripheral distribution within the burner, swirl generation, and mixing patterns were anticipated from the design of the HT-NR design. Testing appeared prudent to evaluate flow performance of the HT-NR burner and to check the influence of streamlining on pressure drop, since available forced draft fan static pressure limits burner pressure drop in retrofit applications. Finally, the fuel jet was seen as a crucial factor in determining overall NO_x performance and flame length. Alteration to the fuel jet momentum and dispersion was expected to provide a measure of control over NO_x and flame dimensions. Flame width and length should be adjustable to tailor flame shape to a given furnace geometry so as to avoid impingement.

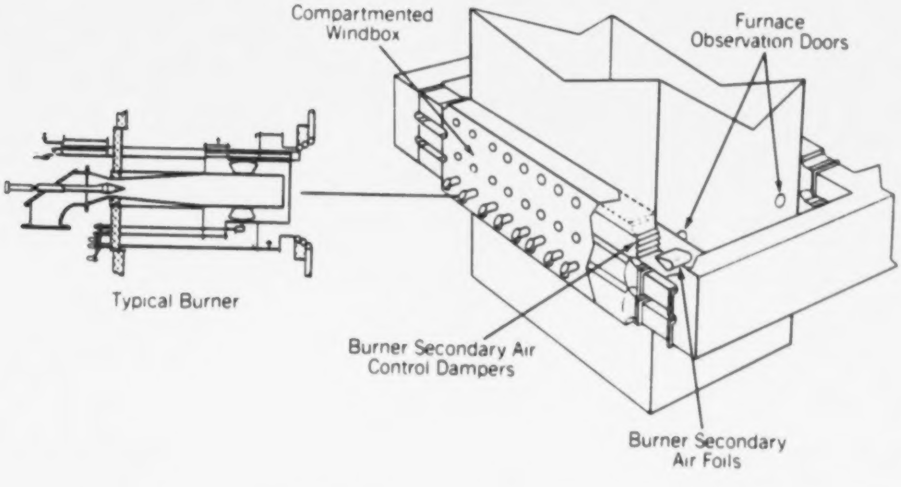

Compartmented Windbox
Furnace Observation Doors
Typical Burner
Burner Secondary Air Control Dampers
Burner Secondary Air Foils

Figure 3 Compartmented Windbox.

The B&W XCL burner (Figure 4) addresses these concerns. Functionally, the XCL burner uses criteria for the HT-NR burner, and its predecessor, the DRB. The prototype XCL uses slide dampers to regulate air flow to the inner and outer air zones, with adjustable vanes in both zones to impart swirl. The air separation vane was retained from the HT-NR burner. Several hardware arrangements were evaluated for the burner nozzle, including the flame stabilizing ring, conical diffuser, and impellers.

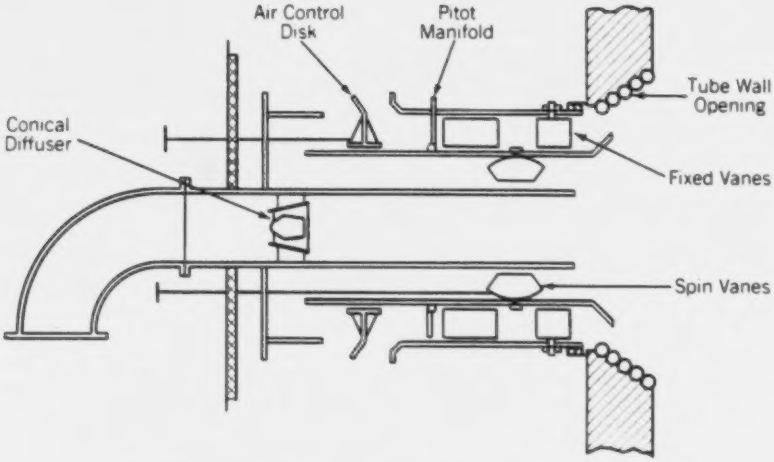


Figure 4 Babcock & Wilcox XCL Burner.

PROGRAM DESCRIPTION AND OBJECTIVES

The U.S. Environmental Protection Agency had expressed interest to B&W in the performance of the HT-NR burner. The EPA was interested in conducting combustion tests with this burner in their Large Watertube Simulator (LWS). Further, it appeared to be a promising candidate for demonstration in the Limestone Injection Multistage Burner (LIMB) project for which B&W was prime contractor to the EPA. It was subsequently agreed that the EPA and B&W would share the cost of a development program to evaluate the HT-NR burner relative to B&W's Dual Register burner and XCL burners.

The LIMB demonstration project called for retrofitting low NO_x burners in Ohio Edison's Edgewater Station Unit 4, in Lorain, Ohio. This unit (Figure 5) is a B&W natural circulation drum boiler rated at 690,000 lb/hr mainsteam flow at 1,480 psig at 1,000°F. The unit is 30 ft wide, 22 ft deep, and 114 ft high from lower headers to the roof. The unit is equipped with four E64 pulverizers, each supplying three burners in an individual burner level (burner matrix is four levels high with three burners per level).

The LIMB demonstration project brought several operating constraints and burner sizing criteria to the program, specifically burner input rating, pressure drop, and flame length (Table 1). Burner input would be 78 million Btu/hr (MKB) and the burner would have to fit the existing walltube opening (no pressure part alterations) and windbox. Taken individually each criterion does not appear too restrictive; however, as a group they multiply the degree of difficulty to achieve

Reproduced from
best available copy.

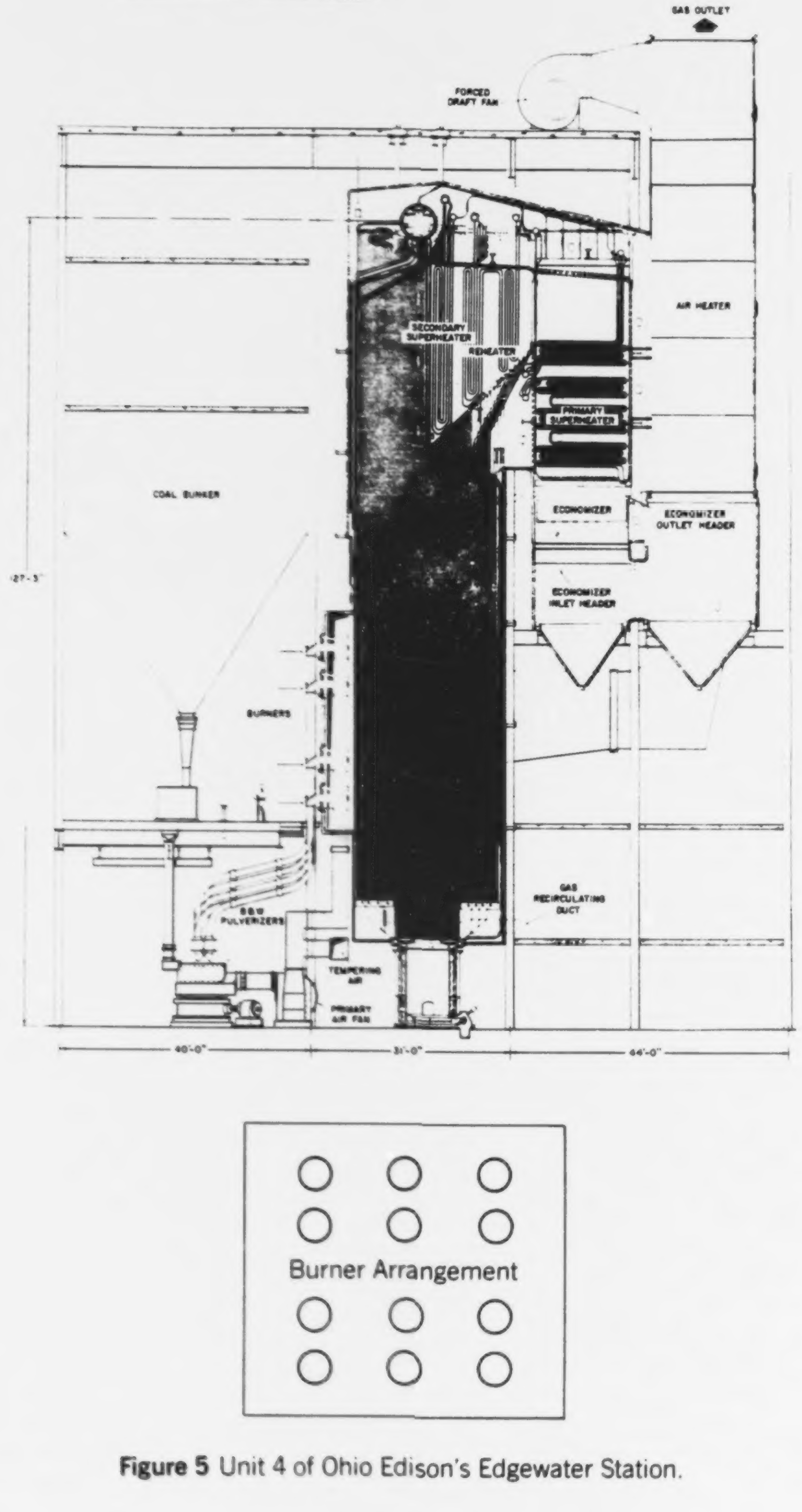

GAS OUTLET
FORCED DRAFT FAN
AIR HEATER
SECONDARY SUPERHEATER
REHEATER
PRIMARY SUPERHEATER
COAL BUNKER
ECONOMIZER
ECONOMIZER OUTLET HEADER
127'-3"
ECONOMIZER INLET HEADER
BURNERS
B&W PULVERIZERS
GAS RECIRCULATING DUCT
TEMPERING AIR
PRIMARY AIR FAN
40'-0"
31'-0"
44'-0"
Burner Arrangement

Figure 5 Unit 4 of Ohio Edison's Edgewater Station.

all simultaneously. To accomplish these goals, a development program was formulated that consisted of three phases:

- Air flow testing.
- Single burner combustion tests.
- Retrofit demonstration at Edgewater 4.

Table 1. BURNER OBJECTIVES AND CRITERIA FOR LIMB DEMONSTRATION

Burner Objective	Criteria
Burner input, 10^6Btu/hr	78
NO_x emissions, lb/10^6 Btu	<0.5
Unburned carbon (in ash), %	<5
Flame length, ft	<22
Burner air resistance, in. H_2O	<5
Burner throat, in.	35 (or less)
Windbox depth, in.	63
Burner depth, in.	49

TEST APPARATUS AND FACILITIES

The air flow and combustion tests involved evaluation of the DRB, HT-NR, and XCL burners. The burner capable of meeting all the objectives was intended for use in the retrofit demonstration. One full scale version of each burner was fabricated to meet the size constraints of Table 1 at the design input. The HT-NR burner was designed according to BHK standards. These criteria were met with a burner throat diameter of 35 in. The burner nozzle diameter and air zone design criteria of the HT-NR were matched for the XCL design. The DRB was sized to meet the same throat diameter as the HT-NR and XCL, which resulted in lower than standard design velocities for the DRB. This was done in the interests of simplifying burner changeover during testing, with the expectation of limited impact on results. During subsequent testing, the actual impact on DRB performance due to the oversized throat was significant; consequently, a true standard DRB was built and tested to establish baseline performance.

Air flow tests were conducted at B&W's Alliance Research Center in Ohio. The test facility is shown in Figure 6. Ambient air was separately measured and controlled to the burner nozzle and to the windbox. Local velocity and swirl measurements were taken in a plane 7 in. downstream of the inlet of the throat cone using a Fecheimer two-dimensional velocity probe. The radial component of velocity in the secondary air region of the burner exit was found by a wool tuft to be such that the flow is parallel to the throat cone. Fecheimer traverses in this plane were taken with the probe perpendicular to the throat cone. Velocity and swirl angle measurements (from which axial and tangential velocity components can be calculated) were obtained. Overall, isothermal burner exit flow profiles were taken downstream of the burner using wool tuft grids. These patterns were used to develop the flow profiles of the burners.

Combustion tests were performed in the EPA's LWS facility operated by the Energy and Environmental Research Corporation, El Toro, California. The LWS furnace (Figure 7) is 16 ft wide and 22 ft deep, conveniently the same furnace depth as the Edgewater 4 unit. The furnace is 50.5 ft high, refractory lined to a height of 16 ft (in addition to the hopper), and spray water cooled on the outer casing.

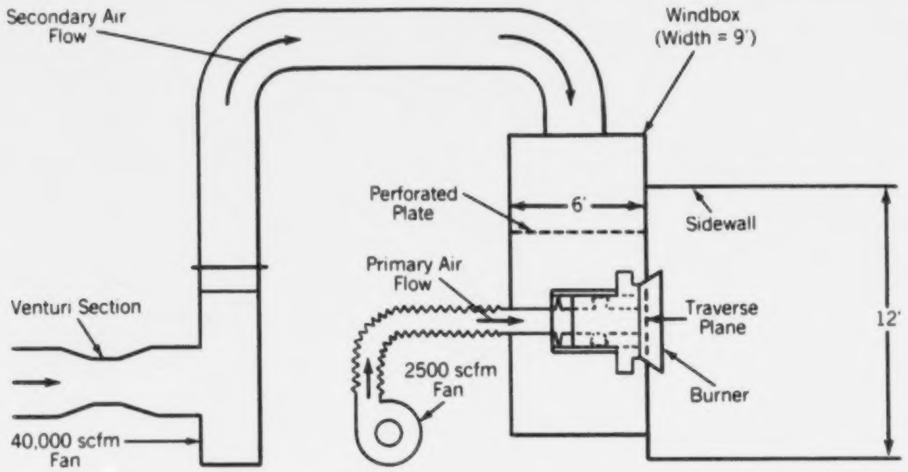

Secondary Air Flow
Windbox (Width = 9')
Perforated Plate
6'
Sidewall
Primary Air Flow
Venturi Section
Traverse Plane
12'
2500 scfm Fan
Burner
40,000 scfm Fan

Figure 6 Full Scale Burner Air Flow Facility.

Secondary air is preheated by an indirect fired airheater and metered and controlled to the windbox attached to the furnace frontwall. A bowl pulverizer directly provides pulverized coal to the burner. Gas is sampled at a multiple point grid in the exhaust duct at about 1,000°F. The sampling system and train for continuous analysis of emissions conforms with EPA Performance Specifications 2 and 3. A data acquisition system provides continuous and time-averaged data collection.

Table 2. COAL AND ASH CHARACTERIZATION

Coal Source:		
	Mine:	Pittsburgh No. 8
	County:	Belmont
	State:	Ohio

Raw Coal and Ash Data (As Received Basis)

Coal Chemical Analysis:		Ash Chemical Analysis:	
Proximate Analysis:		SiO_2	47.44
		Al_2O_3	20.55
Total Moisture:	2.20	TiO_2	0.87
Volatile Matter:	34.10	Fe_2O_3	25.05
Fixed Carbon:	51.01	CaO	1.76
Ash:	12.69	MgO	0.52
		Na_2O	2.00
Btu per lb:	12344	K_2O:	0.32
		P_2O_5	1.11
		SO_3	0.00

Ultimate Analysis:		Ash Fusion Temperatures (°F):	Reducing	Oxidizing
Moisture:	2.20			
Carbon:	69.18			
Hydrogen:	4.67	IDT	2118	2331
Nitrogen:	6.78	AST	2248	2558
Sulfur:	3.33	AHT	2457	2584
Ash:	12.69	AFT	2487	2607

Calculated Results of Characterization Analysis

Rank: High Volatile Bituminous A

FC/VM Ratio:	1.50
C/H Ratio:	2.49
lb Nitrogen per MKB:	0.93

Results Interpretation:

Ash Type:	Eastern Bituminous
Slag Propensity:	Medium
Foul Propensity:	High

The coal used in the combustion test program matched criteria established in the LIMB program. Table 2 shows the coal to be a high volatile bituminous A with high sulfur and a fuel ratio (FC/VM) of 1.5 indicating a reactive coal. B&W empirical indices predict medium slagging and high fouling tendencies.

The combustion test matrix consisted of parametric testing of the DRB, HT-NR, and

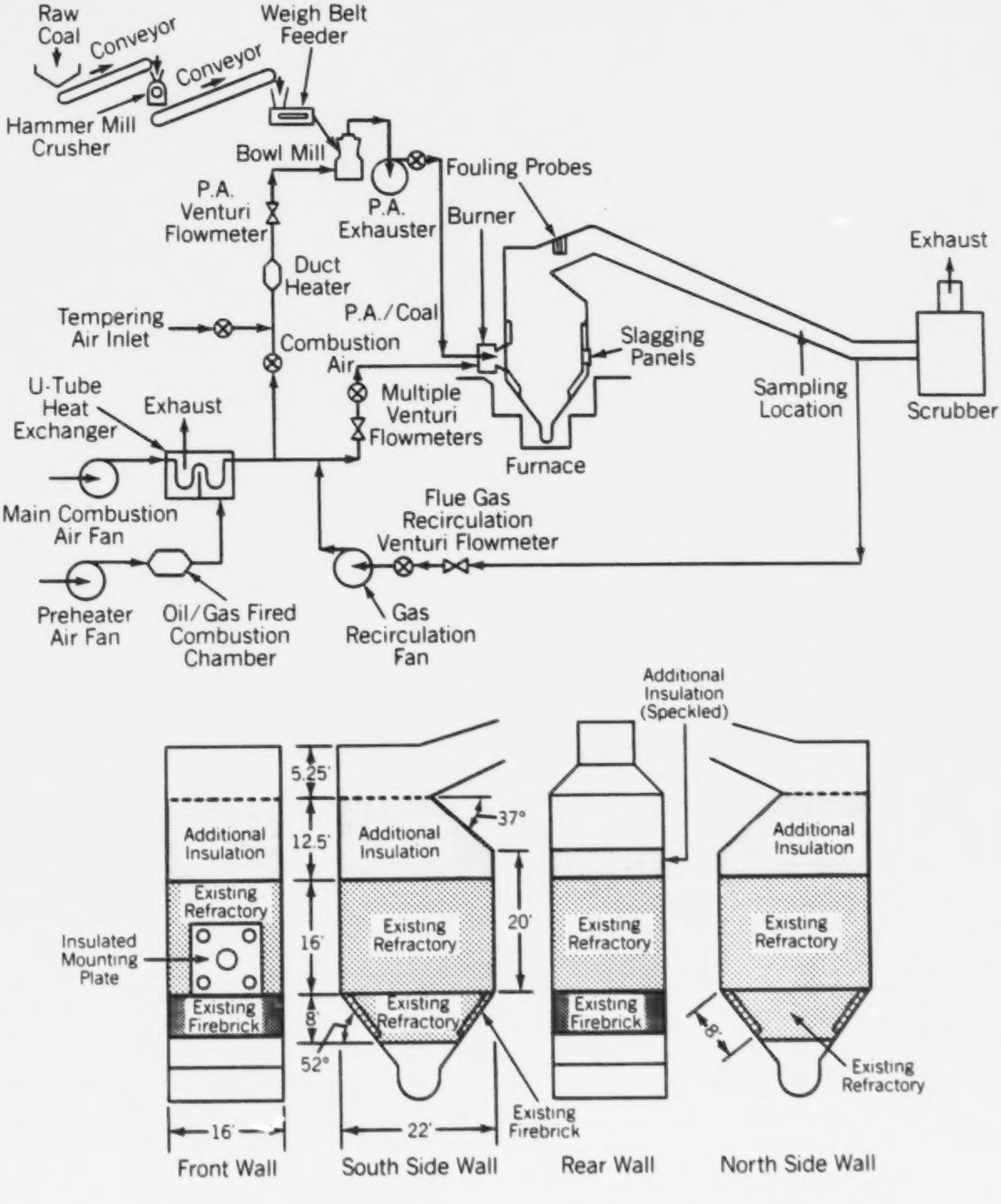

Raw Coal
Conveyor
Conveyor
Weigh Belt Feeder
Hammer Mill Crusher
Bowl Mill
Fouling Probes
P.A. Venturi Flowmeter
P.A. Exhauster
Burner
Exhaust
Duct Heater
P.A./Coal
Tempering Air Inlet
Combustion Air
Slagging Panels
U-Tube Heat Exchanger
Exhaust
Multiple Venturi Flowmeters
Sampling Location
Scrubber
Furnace
Main Combustion Air Fan
Flue Gas Recirculation Venturi Flowmeter
Preheater Air Fan
Oil/Gas Fired Combustion Chamber
Gas Recirculation Fan
Additional Insulation (Speckled)
5.25'
37°
12.5'
Additional Insulation
Additional Insulation
Additional Insulation
Existing Refractory
20'
16'
Existing Refractory
Existing Refractory
Existing Refractory
Insulated Mounting Plate
Existing Firebrick
Existing Refractory
Existing Firebrick
8'
8'
52°
Existing Refractory
Existing Firebrick
16'
22'
Front Wall
South Side Wall
Rear Wall
North Side Wall

Figure 7 LWS Test Facility Arrangement & Furnace Layout.

XCL burners in sequence to screen burner performance. Several hardware variations were performed with each burner to evaluate the effectiveness of certain components, primarily as they affected NO_x, unburned carbon loss (UCL), flame length, and burner pressure drop. All configurations were tested at full load (78 MKB) over a range of burner adjustments and excess air. Key arrangements were further tested over a range of loads, but facility limitations prevented operation below about 45 MKB. The burner of choice from the screening tests was further characterized by tests with a variety of coals, including low volatile bituminous and subbituminous. Major findings are covered here, and complete documentation will be found in the final report to the EPA for this project, to be issued later this year.

The burner selected from the combustion test program was approved by Ohio Edison and EPA for use in the LIMB demonstration. Twelve low NO_x burners were fabricated and installed in Edgewater Unit 4 during August 1986. (Note: performance tests were conducted on the unit prior to this outage to establish baseline conditions with the circular burners.) The low NO_x burners have been undergoing field testing since that time for purposes of shakedown and final tuning to the Edgewater unit. These tests are in progress at this writing, but some data will be presented to indicate results thus far.

RESULTS AND DISCUSSION

AIR FLOW TESTS

Air flow tests performed on the Dual Register burner verified that the axial primary jet penetrated the swirl-induced secondary recirculation zone downstream. In practice, the reverse flow along the boundary of the fuel jet returns hot gases to the ignition zone to stabilize the flame. The HT-NR flow pattern, while similar, has several important differences. Primary jet momentum is disrupted at the nozzle exit by obstructions into the flow stream and the bluff body effect of the collar. This acts to cause localized recirculation patterns at the outer boundary of the primary jet as it leaves the nozzle and reduces primary jet momentum. Swirled air in the inner secondary air zone follows the contour of the Air Separation Vane and attaches to the highly swirled air exiting the outer (tertiary) zone along the burner throat. This highly swirled air stream, physically separated from the primary jet, develops a low pressure zone downstream, which in turn draws the air rapidly back in, developing a recirculation zone. In subsequent combustion tests, with sufficient outer air swirl, it was possible for the secondary induced recirculation pattern to overcome the primary jet and sharply reduce flame length. Pressure drop was measured during the air flow tests and related to velocity head to predict pressure drop with preheated air. This led to a decision to alter the Air Separation Vane during the XCL air flow tests to reduce resistance. Air flow patterns of the XCL generally followed those of the HT-NR, although maximum swirl generation was less. Pressure drop readings across the XCL were reduced 32% by streamlining flow and other modifications.

Figure 8 compares velocity profiles measured at a plane in the burner throat for the three burners. The break in the curves is due to low velocity recirculation in the area downstream of the inner air zone, which could be evidenced by wool tufts but not accurately measured. The HT-NR displayed the highest velocity profile peak due to highly swirled air moving in a narrow band along the wall of the throat. The XCL showed a similar pattern but at lower velocity. Concerns about high pressure drop discouraged raising the swirl generating capability of the XCL to match the HT-NR.

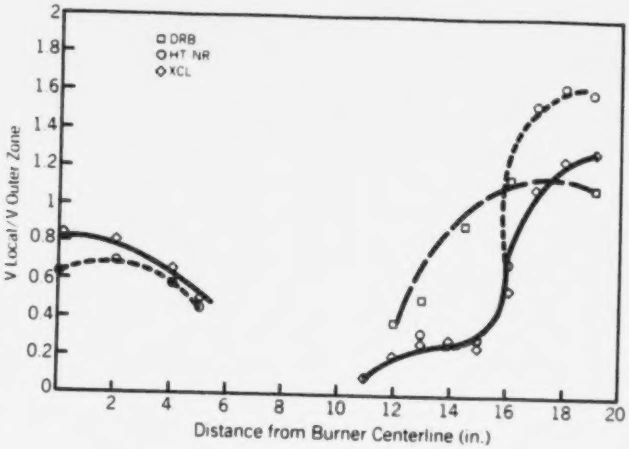


Figure 8 Velocity Profile Comparison. DRB, HT-NR, & XCL Burners.

COMBUSTION TESTS

Dual Register Burner

The Dual Register burner (with a 35 in. throat) was the first burner tested in the LWS in this program. NO_x appeared unusually low for the DRB firing bituminous coal, with results averaging 210 ppm at 3% O_2 (all concentrations are reported at 3% O_2) or 0.29 lb/MKB, at full load and 18% excess air. Flames appeared somewhat lazy, and flame length in every case greatly exceeded the 22 ft criterion. Unburned carbon loss (UCL) was in the 3 to 6% range (reported as percent combustible in fly ash). The facility operators advised that UCL levels of less than 10% should be considered very good in this furnace and that field values would be lower.

An impeller, of the type used in B&W circular burners, was installed in the DRB burner nozzle to simulate circular burner performance. Previous operating experience with DRB burners and impellers, circular burners, and the LWS test results are compared in Table 3. The field results (opposed fired utility boiler) indicated the DRB with this type impeller produced NO_x emission similar to a standard circular burner (640 and 700 ppm, respectively). This is not unexpected: this impeller rapidly disperses the coal into the secondary air, eliminating the delayed diffusion/fuel rich zone normally produced by the DRB. The field data for the DRB burners without an impeller were 330 ppm, representing a 48% reduction relative to the DRB plus impeller burner. By comparison, the LWS tests resulted in 660 ppm NO_x for the DRB plus impeller (close to the 640 ppm field value) but produced 210 ppm without the impeller (versus 330 for the field). The LWS test resulted in a 68% NO_x reduction by removing the impeller. The conclusion was drawn that the DRB tested in the LWS was producing uncharacteristically low NO_x. This was attributed to the oversized burner throat (refer to Test Apparatus for a description) and lower velocities with this DRB compared to standards. While the low NO_x performance was virtuous, the long flames exceeded the project objectives.

Since the large throat DRB results were significantly different than expected, a second DRB designed to B&W standards was later tested to establish baseline emissions for the program. The standard DRB with a venturi diffuser in the burner nozzle averaged 278 ppm NO_x (0.38 lb/MKB) at full load, 18% excess air, and NO_x ranged from 230 to 319 ppm depending on burner adjustments. NO_x emissions were also sensitive to load and excess air. UCL results were good, ranging from 2 to

6%. Flame length was controllable to about 20 ft with high swirl and high burner differential, 10 in. H_2O. Reducing swirl brought windbox pressure in-line with objectives, but flame length exceeded 22 ft. Flames were stable at all test conditions, regardless of load or register adjustments. CO emissions were less than 50 ppm except at low excess air test conditions.

Table 3. BURNER PERFORMANCE COMPARISON

	Field Data[a]	LWS Data[a]
Circular Burner (with impeller)	700	(700)[b]
DRB with Impeller	640	660
DRB without Impeller	330	210

[a] - NO_x @ 3% O_2.
[b] - Approximate.

The standard DRB was also tested with the B&W conical diffuser in the burner nozzle. NO_x typically averaged 268 ppm (0.37 lb/MKB) with the conical diffuser and ranged from 202 to 320 ppm, depending on burner settings at full load with 18% excess air (Figure 9). Point-to-point comparisons with the venturi (Figure 10) showed approximately a 12% reduction with the conical diffuser. UCL was satisfactory, and other performance was like the venturi diffuser nozzle.

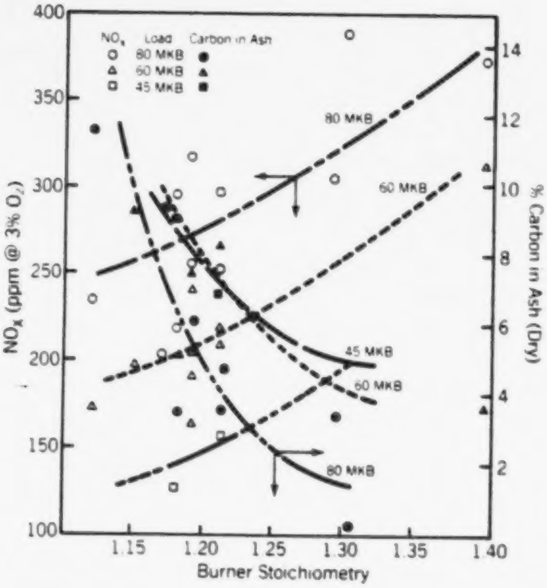


Figure 9 Dual Register Burner Performance with Conical Diffuser.

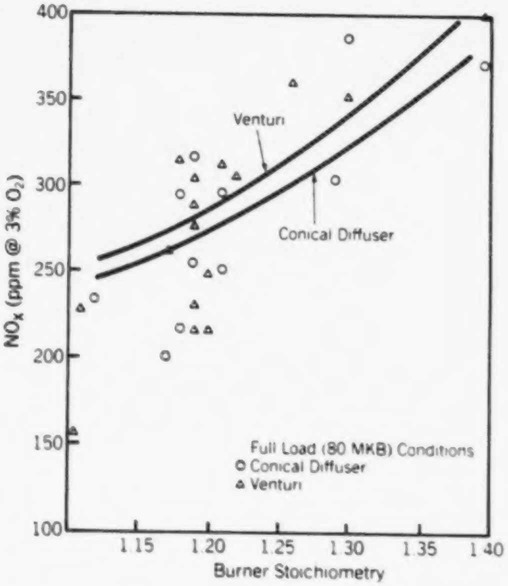


Figure 10 Dual Register Burner Venturi vs. Conical Diffuser.

In summary, the DRB satisfied the NO_x, UCL, and mechanical requirements, but required excessive burner resistance to meet the flame length criterion. The standard impeller reduced flame length but with high NO_x emissions.

HT-NR Burner

The HT-NR burner was tested in several configurations, but only the optimum configuration is detailed here. Shakedown tests indicated that use of the conical diffuser ahead of the flame stabilizing ring produced lower NO_x results (about 40 ppm) than the swirler at the best conditions of both. The conical diffuser was used for all subsequent tests. The air register assembly was modified with BHK's assistance during the tests to generate more swirl. Prior to register modifications, NO_x emissions were typically 240 ppm (full load, 18% excess air) with flame lengths of 20 to 21 ft , UCL about 3%, and burner resistance of 7.5 in. H_2O.

Following register modifications for increased swirl, NO_x emissions at full load (18% excess air) averaged 195 ppm (0.27 lb/MKB) and ranged from 190 to 310 ppm, depending on register adjustments. Full load NO_x emissions varied from 147 to 297 ppm as excess air increased from 7 to 37%. Unburned carbon was low (Figure 11), amounting to about 3% at full load with 18% excess air. Flame length increased to over 22 ft with a corresponding burner resistance of 7 in. H_2O. At maximum swirl conditions, flame length could be reduced to about 19 ft , but burner resistance increased to 13 in. H_2O. Flame stability was excellent over the load range regardless of burner adjustments. CO emissions were typically less than 25 ppm at full load.

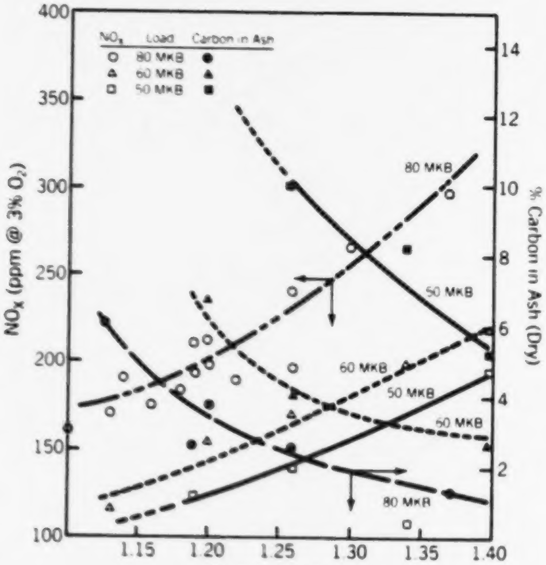


Figure 11 HT-NR Burner Performance.

The effect of coal fineness on NO_x was briefly investigated with the HT-NR burner. Fineness (expressed as percent passing a 200 mesh sieve - minus 74 μm) was increased from 70 to 82% without any change in NO_x. However, when primary air flow was increased 12% in addition to the higher fineness, NO_x decreased from 190 to 170 ppm, about 10%. Corresponding flame length exceeded 22 ft.

In summary, the HT-NR proved capable of very low NO_x emissions with low levels of UCL and excellent flame stability, and satisfied mechanical size limitations. NO_x emissions were typically 30% less than the DRB with venturi. Pressure drop and flame length exceeded the program objectives.

XCL Burner

The XCL burner tested in the LWS was equipped with the Air Separation Vane, and the secondary air zones were sized in accordance with HT-NR standards for the flow rates and velocities. The XCL was first tested with a conical diffuser in the burner nozzle. At full load with 18% excess air, NO_x emissions were 237 ppm (0.32 lb/MKB) with burner resistance of 5 in. H_2O, and UCL was 7%. Flame lengths exceeded 22 ft except at very high swirl and accompanying high burner resistance (10 in. H_2O). Flame stability was excellent over the range of load and burner adjustments.

A flame stabilizing ring was then installed in combination with the conical diffuser. This resulted (Figure 12) in NO_x emissions (full load, 18% excess air) which averaged 204 ppm (0.28 lb/MKB) and ranged from 190 to 276 ppm depending on burner adjustments. Burner resistance was typically 3.5 in. H_2O and flame lengths exceeded 22 ft except at very high swirls and high resistance (12 in. H_2O).

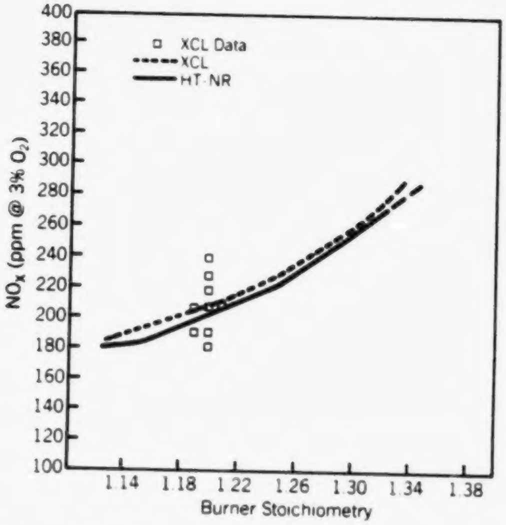


Figure 12 XCL Burner Performance Compared to HT-NR Burner at 80 MKB.

Screening Test Evaluation

Following these tests, the results of the DRB, HT-NR, and XCL burners were evaluated relative to the program objectives, summarized in Table 4. The NO_x emission limit of 0.5 lb/MKB was easily met by the DRB, HT-NR, and XCL burners. The DRB was typically less than 0.4 lb/MKB, and the HT-NR and XCL achieved less than 0.3 lb/MKB. In comparison to uncontrolled emissions, the DRB achieved 60 to 62% NO_x reductions, while the HT-NR and XCL burners achieved over 70% NO_x reductions. Combustion efficiency was simultaneously very good, with low CO levels and unburned combustible in the fly ash of 2 to 7%. (Note: the facility operators' experience indicated that UCL levels in the field would be lower, while NO_x emission was predicted to increase about 10% in the application at Ohio Edison's Edgewater 4 Unit.)

The primary concern was the strong tendency of the flames to exceed the 22 ft limit at full load conditions. In most cases, high secondary air swirl would reduce flame length to just under 22 ft. But the accompanying burner air side resistance would increase to 8 to 13 in. H_2O and greatly exceeded the program objective in this regard. It was concluded that use of secondary air swirl to control flame length was not satisfactory. The alternative proposed was to reduce fuel jet momentum to reduce flame length while maintaining moderate burner resistance. The XCL had demonstrated very low NO_x emissions with low burner resistance, so the decision was made to pursue flame length optimization using the XCL burner.

Table 4. BURNER PERFORMANCE SUMMARY - FULL LOAD, 18% EXCESS AIR (LWS TEST FURNACE)

Condition	NO_x ppm (@ 3% O_2)	NO_x lb/MKB	Flame Length (ft)	Burner ΔP (in. w.c.)	Unburned Combustible (% in fly ash)	NO_x Reduction Relative to Uncontrolled (%)
Program Objectives	267	0.50	≤22	≤5.0	5	
Uncontrolled (Circular Burner)[a]	700	0.95	13	2.5	2-3	0
DRB & Wide Impeller	660	0.90	16	-	1-2	6
DRB & Venturi	278	0.38	>22[b]	5.5	2-6	60
DRB & Con. Diff.[c]	268	0.37	>22[b]	4.5	2-6	62
HT-NR & Swirler	280	0.38	>22[b]	5.0	3	60
HT-NR & Con. Diff.	240	0.32	21	7.5	3	66
HT-NR & Con. Diff. Plus High Swirl	195	0.27	>22[b]	7.0	3	72
XCL & Con. Diff.	237	0.32	22[b]	5.0	7	66
XCL & Con. Diff. & FSR	204	0.28	22[b]	3.5	NA	71

a - Estimated results

b - Flame could be shortened to less than 22 ft with 8-13 in. w.c. burner ΔP

c - Conical diffuser

XCL BURNER CHARACTERIZATION TESTS

The XCL burner was subsequently tested with several devices designed to reduce fuel jet momentum, including burner nozzle modifications to reduce exit velocity and a device which preferentially reduced fuel velocity while accelerating primary air velocity. In addition, several types of impellers were used to impart radial deflection to the fuel jet and thereby reduce the axial component of velocity. Four of the configurations proved to be capable of simultaneously satisfying program objectives for NO_x, flame length, and burner resistance. The most versatile of these was an impeller used with the standard burner nozzle, as shown in Figure 13. This modified impeller imparts less deflection on the fuel stream compared to the standard impeller reported previously with the DRB. Figure 14 shows the relationship between flame length and NO_x at full load, 18% excess air conditions. The flame length could be varied by burner adjustments much more effectively when the XCL was equipped with the impeller. The data in Figure 14 represent moderate burner resistance; i.e., 3.2 to 5.5 in. H_2O. The lowest NO_x levels were achieved by partially retracting the impeller into the coal nozzle to lessen its ability to flare the fuel jet. A shorter flame (with higher NO_x) was repeatedly produced with the impeller at the normal location at the nozzle exit. A longer flame (with lower NO_x) was repeatedly produced with the impeller retracted to the preferred alternate setting. However, the impeller in positions intermediate to these produced a long or short flame depending on how the condition was approached. (Note: Figure 15 represents repeatable conditions that were outside of the hysteresis band.)

Unburned carbon loss was in the 4 to 7% range during these tests (Figure 15), and was expected to be lower in field applications. However, B&W decided to modify the air swirl vanes in the outer (tertiary) zone to improve peripheral air distribution in order to reduce UCL. Dual stage swirl vanes were installed in the XCL outer zone for this purpose. Figure 14 shows that NO_x and flame length relationships were nearly the same. Unburned carbon was excellent (Figure 15), in the 2 to 3% range (full load, 18% excess air). Burner resistance was typically 4.1 in. H_2O with this arrangement.

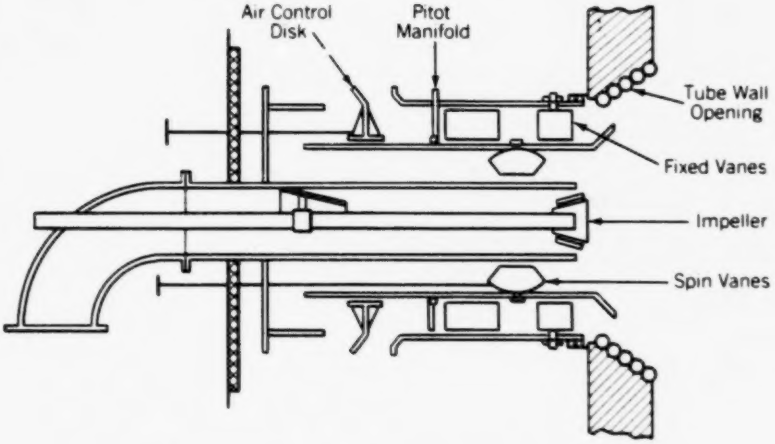
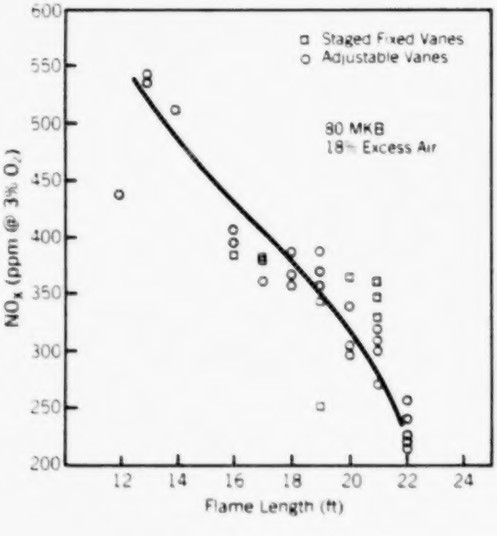


Figure 13 Babcock & Wilcox XCL Burner with Impeller.



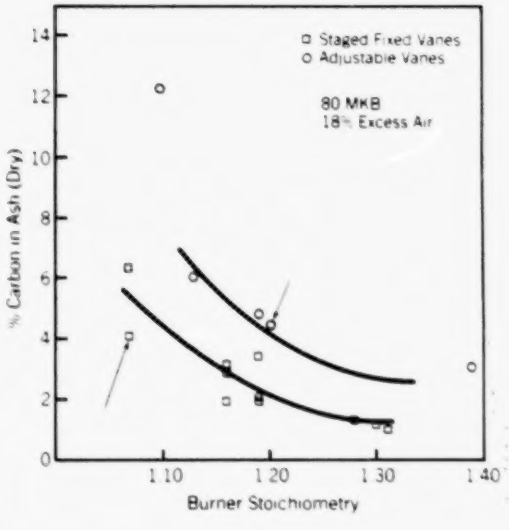


Figure 14 NO_x vs. Flame Length for XCL Burner. XCL Burner Plus Modified Impeller.

Figure 15 Combustion Efficiency for XCL Burner. XCL Plus Modified Impeller.

Therefore, with a modified impeller and dual stage air vanes, the XCL burner satisfied all program criteria simultaneously. NO_x was variable from about 0.3 to 0.6 lb/MKB (0.5 lb/MKB goal) with: flame lengths from over 22 to 12 ft (22 ft goal), burner resistance near 4 in. H_2O (5 in. H_2O goal), and UCL of 2 to 3% (5% goal). The mechanical size limitations were also satisfied in this design.

To more fully characterize the XCL burner in this configuration, additional tests were conducted on two alternate coals--a western bituminous Utah coal and a lower volatile eastern bituminous (Lower Kittaning). Key fuel parameters are summarized in Table 5, and full load performance results are shown in Figure 16. The Utah coal resulted in NO_x emissions and unburned carbon levels very similar to the base Pittsburgh 8 coal. The Lower Kittaning coal produced higher NO_x emissions and higher unburned carbon levels as well. The previous discussions on the significance of volatile matter on NO_x control support this trend; i.e., the lower volatile coal released less fuel nitrogen and generated fewer hydrocarbon radicals in the fuel rich portion of the flame and consequently increased overall NO_x emissions.

Table 5. XCL TEST COALS

Analysis (as received)	Fuel Lower Kittaning	Utah
Moisture	3.66	5.46
Ash	10.75	10.00
Volatile Matter	22.28	38.26
Fixed Carbon	63.31	46.28
Higher Heating Value, Btu/lb	13330	11930

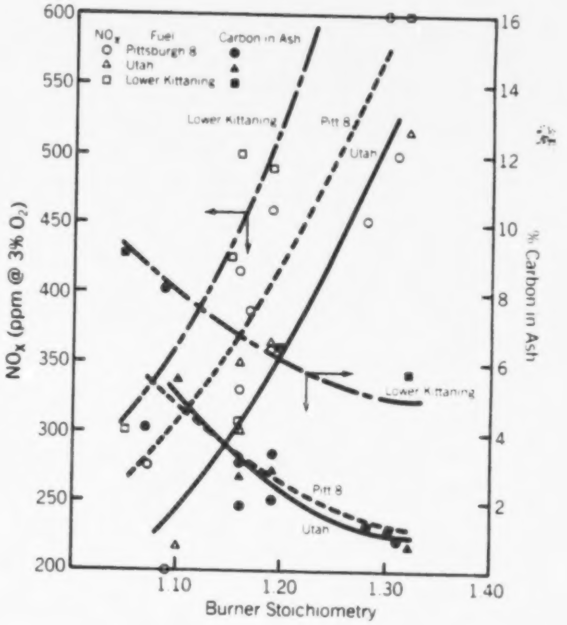


Figure 16 Fuel Effects: XCL Burner Plus Modified Impeller.

LIMB DEMONSTRATION

With concurrence from Ohio Edison and the EPA, B&W manufactured 12 full-scale XCL burners for installation at Ohio Edison's Edgewater Station Unit 4. Figure 5 shows the furnace and burner arrangement. (Note: investigation outside of this program had determined that the optimum sorbent injection locations were in the upper furnace, meaning that no sorbent injection equipment was installed in the burners.)

Prior to the XCL burner installation, baseline tests were performed on the boiler with the existing circular burners. B&W inspected and tuned the burners prior to these tests. Figure 17 summarizes NO_x and UCL results from the tests and also lists pertinent information about the coal. The excess air values were determined from a multipoint gas sampling grid installed at the airheater inlet. These readings were compared to O_2 measurements taken in a vertical plane at the entrance to the boiler convection pass (at the furnace exit). The difference in excess air measurements between the furnace exit and the airheater is due to air infiltration to the setting. These tests were performed at three loads to account for infiltration variances with load. The results were used to correct excess air values measured at the airheater inlet in all subsequent tests. In essence, NO_x emissions were typically 650 ppm (0.89 lb/MKB) at full load with 3% excess O_2 and 2.0% carbon in the fly ash (from isokinetic dust sampling). Flames were about 12 ft long.

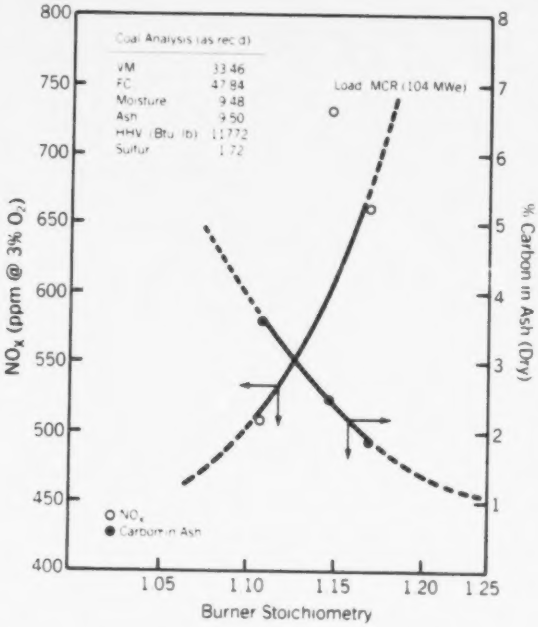


Figure 17 Baseline Performance of Ohio Edison's Edgewater Station - Unit 4 with Circular Burners.

The XCL burners were installed during a 6-week outage which concluded in September 1986. Early test results, listed as Condition 1 in Table 6, indicated that NO_x emissions were slightly above the program goal of 0.5 lb/MKB and that flames were relatively short. This indicated a need to tune the burners to the Edgewater furnace. The bottom burner elevation had longer flames than the other rows as a probable consequence of their proximity to the furnace hopper cooling surface. Consequently, these burners were not adjusted further. The impellers in the upper three burner rows were retracted and produced results listed as Condition 2 (Table 6). NO_x emissions were reduced to 0.38 lb/MKB but CO emissions unexpectedly increased to high levels. Flame lengths were acceptable. B&W sampled furnace gas near the walls at several locations in the combustion zone to determine if H_2S was present at levels which would cause tube wastage. Gas analysis indicated H_2S levels less than 10 ppm, even under conditions with elongated flames, and these were considered to be innocuous (1). The high CO emissions encountered with retracted impellers had not been observed during earlier single burner tests in the LWS. This led to tests to check air/fuel balance between burners, which indicated air deficiency to the left-hand burners. Biasing air to these burners reduced CO to background values while maintaining low NO_x (Condition 3 in Table 6).

Table 6. LIMB - XCL BURNER CHARACTERIZATION/OPTIMIZATION PERFORMANCE DATA

	NO_x lb/10^6 Btu	CO ppm @ 3% O_2	% Carbon in ash	Burner ΔP in.H_2O	Flame Lengths ft
Program Goals	<0.50 (0.40)		≤5.0%	≤5.0	<22
Burner Configuration					
1. Initial - 30 deg impeller 45 deg outer vanes	0.53 (0.49-0.58)	115 (40-140)	~2.8	4.5-5.5	15-18
2. Retract impellers 12" on top 3 rows to simulate conical diffuser	0.38 (0.34-0.40)	2500 (830-3000)	N/A	4.5-5.5	18-22
3. Bias air to lower west burner zone (1 test point)	0.40	75	N/A	5.3	18-22
4. Replace retracted impellers on top 3 rows with standard coal distribution equipment (conical diffuser/deflector)	0.35 (0.31-0.41)	700 (100-2000)	11.2 (6.5-14.6)	4.8-5.0	18-22

All data is full load, normal O_2
(3.0-3.5% O_2 furnace outlet, 4.5-5.0% O_2 at air heater inlet)

Conical diffusers were installed in the top three burner elevations to permanently provide the mixing function of the retracted impellers. High CO and unburned combustibles returned sporadically (Condition 4 in Table 6), and furnace probing revealed major air/fuel imbalances. (Note: the conical diffusers reduce pulverizer-to-furnace pressure drop and could have changed fuel distribution among burners.)

The commissioning process has indicated a tendency in this unit for significant air/fuel maldistribution. This is probably the consequence of furnace size, coal piping and burner arrangement, and pulverizer controls. NO_x emissions below present NSPS were readily achieved with good combustion performance. NO_x was further reduced to 0.35 lb/MKB, by addition of conical diffusers, but further air/fuel imbalance resulted. Steps are presently being taken to confirm stoichiometries of the furnace and to balance these mixtures. However, this program has shown the difficulty in achieving very low NO_x emissions by burner retrofits to existing boilers, which place a variety of constraints upon adaptation. These difficulties appear resolvable, but require more tuning of the combustion system to the boiler.

CONCLUSIONS

- The HT-NR and XCL burners produced 25 to 30% lower NO_x emissions than the Dual Register burner, while providing efficient combustion.

- A strong dependence was observed between NO_x emissions and flame length. Lowest NO_x emissions were usually accompanied by relatively long flames, and measures which reduced flame length increased NO_x.
- Flame length could be reduced by high recirculation induced by high secondary air swirl and accompanied by high burner resistance. Flame length was also reduced by several devices which reduced fuel jet momentum, but NO_x emissions increased somewhat.
- Retrofit application of B&W XCL burners to a 104 MW utility boiler resulted in NO_x emissions of about 0.5 lb/million Btu while achieving less than 3% carbon in the ash, and with moderate burner resistance and flame length. NO_x ports were not required. Lower NO_x emissions can be attained but require burner/boiler tuning.

CONVERSION FACTORS

Readers more familiar with metric units may use the following to convert the non-metric units used in this paper.

Non-Metric	Times	Yields Metric
Btu	1.055	kJ
°F	5/9 (°F-32)	°C
in.	2.54	cm
ft	0.30	m
lb	0.45	kg
$lb/in.^2$	703.1	kg/m^2
$lb/10^6$ Btu	0.43	$kg/10^6$ kJ

REFERENCES

1. Chou, S. F., et al., "Fire-side Corrosion in Low NO_x Combustion Systems," In Proceedings: 1985 Symposium on Stationary Combustion NO_x Control, Volume 1, EPA-600/9-86-021a (NTIS PB86-225042), July 1986.

2. Pershing, S. W. and Wendt, J. O. L., "Pulverized Coal Combustion: The Influence of Flame Temperature and Coal Combustion on Thermal and Fuel NO_x," 16th Symposium on Combustion, p.389, Combustion Institute, Pittsburgh, PA (1977).

3. Pohl, J. H. and Sarofim, A. F., "Devolatilization and Oxidation of Coal Nitrogen," 16th Symposium on Combustion, Combustion Institute, Pittsburgh, PA (1977) pg. 491.

4. Narita, T. et al., "Development of the Low-NO_x Burner for Pulverized-Coal-Fired In-Furnace NO_x Reduction System," In Proceedings: 1985 Symposium on Stationary Combustion NO_x Control, Volume 1, EPA-600/9-86-021a (NTIS PB-86-225042), July 1986.

REDUCTIONS IN NO_x EMISSIONS FROM A 500MW CORNER FIRED BOILER.

J.W. Allen+, W.J.D. Brooks*, N.A. Burdett**,
F. Clarke***, G. Foley****.
+NEI International Combustion Ltd., Sinfin Lane,
Derby, DE2 9GJ, United Kingdom.
*Central Electricity Generating Board,
Generation Development and Construction Division,
Barnett Way, Barnwood, Gloucester, GL4 7RS, United Kingdom.
**Central Electricity Generating Board,
Technology Planning and Research Division,
Marchwood Engineering Laboratories, Marchwood,
Southampton, SO4 4ZB, United Kingdom.
***Central Electricity Generating Board, OED, Midlands Area,
Ratcliffe-on-Soar, Nottinghamshire, NG11 0EE, United Kingdom.
****Central Electricity Generating Board,
Fiddler's Ferry Power Station, Widnes Road, Cuerdley,
Warrington, WA5 2UT, United Kingdom.

ABSTRACT

The Central Electricity Generating Board is investigating methods for reducing the emissions of NO_x from fossil-fired power stations. Low-NO_x technologies usually involve radically different combustion regimes within the boiler compared to conventional units and, therefore, it is necessary to investigate their cost-effectiveness by undertaking large scale and long term trials. This paper reports on the results of a programme undertaken to investigate the characteristics of the 'rich-fireball' technique installed in a 500MW(e) coal fired boiler at Fiddler's Ferry Power Station, England. Data are presented showing the impact of operational parameters on NO_x emissions. It is concluded that the introduction of this technique has resulted in a reduction of NO_x emissions of between 31 and 38%, depending on the mills in service.

INTRODUCTION

The Central Electricity Generating Board's power system has a capacity of over 51GW(e), with a substantial fraction being fossil fuelled. In the financial year 1985-1986 for example, 227.5 TWh were generated, 83.7% from coal or oil-fired stations, burning in the process about 84.3 million tonnes of coal equivalent. The consumption of this amount of fuel implies the concomitant release into the environment of significant quantities of pollutants such as NO_x, which may contribute to the acidification of rain and to the production (together with hydrocarbons from other sources) of photochemical oxidants such as ozone. Although it is currently difficult to define and quantify the relationship between emissions and effects on ecosystems, the CEGB has in place programmes aimed at identifying the most cost effective techniques that could be applied in reducing NO_x emissions from its plant.

Commercially available emission control technologies have been assessed in detail to determine which of them are capable of being applied to CEGB boilers to achieve substantial reductions in pollutant concentrations without excessive and unjustified costs being borne by the electricity consumer. The use of low-NO_x burners has been identified as the most cost-competitive option for NO_x control and programmes are underway to develop and test such systems. Technologies applicable to both new and existing furnaces are being examined although the experience obtained by the CEGB is currently confined to the latter category.

Retrofit trials have been designed to establish the precise economic and engineering implications of the current 'state of the art' burners for both corner and wall-fired boilers. This paper reports on such a system on a 500MW(e) corner-fired boiler located at Fiddler's Ferry Power Station, Cheshire. In November 1984, the CEGB made the decision to equip one of the boilers at this station with low-NO_x burners, to conduct trials to assess the effectiveness of the modification, and to make a total commercial assessment of the system.

The objectives of the tests were:

(1) To minimize the NO_x emissions from the modified boiler by using the results of short, well-controlled tests to optimize the overfire air damper positions, secondary air offset angle and overfire air tilt angle consistent with an acceptable operating regime. These settings would then become the standard for longer term operation.

(2) To characterize and compare the emissions and boiler performance of the 'baseline' and modified units (the latter after optimization) by carrying out short tests under well controlled conditions, varying a single operational parameter (e.g. load, O_2, burner tilt) at a time.

(3) To assess the long term performance of the modified boiler by monitoring emissions during normal commercial operation.

SYSTEM CONSIDERATIONS.

The majority of the NO_x produced during the combustion of coal originates from the nitrogen which was originally bound in the fuel. (For typical UK coals the nitrogen content is around 1.2 - 1.9% by weight on a dry, ash free basis). Suppression of this 'fuel-NO_x' is generally achieved by staging the flame, that is by providing an initially fuel rich zone (in which a large fraction of the fuel-nitrogen is converted to N_2 rather than NO), followed by a region in which the remainder of the air is gradually mixed into the primary zone combustion products in order to complete the burnout. Fuel-rich zones are generally produced by diverting air around the burner region through overfire air ports or by biassing the fuel/air distribution in the burner itself.

All low NO_x systems being offered commercially ought to be designed to avoid any impairment of boiler performance due to a lowering of the combustion intensity or formation of substoichiometric regions adjacent to the boiler tubes. The latter is of great importance since fireside corrosion of furnace wall evaporator tubes has in the past been correlated with long periods of exposure to reducing conditions and there is, therefore, great concern that low-NO_x technologies would exacerbate current corrosion problems. In this context, it is of great relevance that the chlorine content of UK coals is high by international standards (being up to 1% by weight on a dry, ash-free basis) since chlorine has been implicated in many recent cases of severe boiler tube corrosion within CEGB plant. Examination of the mechanisms of the attack of combustion products on metal tube surfaces has indicated that chlorine can play a major role in accelerating corrosion by providing a scale disruption mechanism as well as a rapid transport route for corrosion products.

The possibility of enhanced corrosion has considerably influenced the applicability of potential low-NO_x systems to CEGB plant. The implication is that NO_x reduction techniques will only be acceptable in the UK if they are inherently able to continuously maintain an oxidising environment at the furnace walls to minimize corrosion. The areas of boiler tubing subject to high corrosion rates in the unmodified units at Fiddler's Ferry are currently contained commercially by the use of either expensive, corrosion-resistant (co-extruded) tubing or thick wall tubes. Concern has been expressed that this region might be enlarged or move after fitting the new burner system. There is, therefore, a requirement that the fuel-rich regions of the flame, so important for NO_x reduction, must be completely surrounded by a blanket of air. One of the features of the system installed at this station (described in detail below) is the deliberate re-alignment of the secondary air injection nozzles so as to provide an oxidising 'blanket' around the boiler walls. The efficiency of this technique in allowing a reduction in NO_x without concomitant enhanced corrosion is currently being investigated over a three year period, this being the minimum time required to properly assess the effects of a low-NO_x system upon tube corrosion.

PLANT DESCRIPTION.

At Fiddler's Ferry Power Station, there are four 500MW(e) units. The boilers are of NEI-ICL design operating at 180 bars drum pressure with MCR steam flow rates of 1.6×10^6 Kg/hr. The furnaces of each boiler are divided into two tangentially- fired combustion chambers by a suspended water wall. The pulverised fuel for each boiler is supplied by six Lopulco LM 45/3P mills which each discharge into one of six burner nozzles in each of the eight corners of the combustion chambers. Full boiler load can be achieved with five mills in service with normal coals. The whole corner assemblies are designed to be adjustable in a vertical plane over a range of ±20° about the horizontal. Recent practice at Fiddler's Ferry has been for the tilt to be kept around the horizontal position but adjustment is still possible.

The modifications to the burners on No.1. unit were carried out by NEI-ICL Ltd. and are based on a system developed in the USA by Combustion Engineering (1) known as the Low-NO_x Concentric Firing System (LNCFS) or 'rich-fireball'. The concept of the LNCFS is to limit the conversion of fuel-bound nitrogen to NO_x by ensuring that the initial combustion of the coal volatiles occurs under fuel rich conditions whilst maintaining sufficient total excess air to ensure complete combustion. The physical separation of the fuel and air streams necessary to meet these objectives is achieved by a combination of three methods. Firstly, the combustion zone is enriched by directing a proportion of the secondary air (in this case just less than 20%) through overfire air ports above the top burner levels. The overfire air ports have been sized to maintain an overall stoichiometry of 1.05 in the combustion zone during normal conditions. The overfire air not only restricts the oxygen immediately available to the fuel at the burner but provides the air to complete the combustion process and react with nitrogenous intermediates formed during the initial combustion stage. Secondly, the secondary air admitted through the coal burner itself is reduced by blocking off some of the air ports above and below the primary air/p.f. nozzle and the remaining flow is directed away from the primary stream by means of deflectors. Thirdly, the main stream of secondary air into the furnace between the p.f. ports is directed to the outside of the coal firing circle and along the furnace walls. This delays mixing and also forms an oxidising layer along the furnace walls to minimize the likelihood of reducing conditions which would promote fireside corrosion. In the design installed at Fiddler's Ferry, the secondary air offset angle (or yaw) was 17.5° with a facility to vary this angle by another ±7.5°.

The quantity of overfire air admitted to the furnace can be restricted as required since the overfire air ports contain two dampers (large and small) which can be independently operated. Additionally, the overfire air ports can be tilted with the main burner ports and independently to an angle of 10° greater than the main burner tilt. Figure 1 shows schematically the differences between a standard burner box at Fiddler's Ferry and the low-NO_x burner box.

RESULTS

TRIAL ORGANIZATION.

The evaluation of the low-NO_x system was envisaged as a three stage exercise:-

Phase 1... baseline tests on a similar but unmodified unit at Fiddler's Ferry (May, 1985).

Phase 2... short term performance trials on the modified unit (October-December, 1985).

Phase 3... long term tests on the modified boiler. (October 1985 - October 1988).

This paper reports primarily on the results on Phases 1 and 2, although some preliminary data from Phase 3 is presented. Concentrations of NO_x are reported throughout on a dry gas basis, referred to a 3%O_2, dry gas, content.

The fuel burnt during the tests reported here was a reasonably consistent blend of bituminous coals with a mean analysis (as received) of 10.1% moisture, 12.7% ash, 28.7% volatile matter and 48.5% fixed carbon. The mean gross calorific value (as received) was 26.8 MJ/kg and the mean nitrogen content 1.62% (dry).

INSTRUMENTATION.

For the short term tests (Phases 1 and 2) described here, NO_x measurements were made using an extractive system, sampling gas from points at the outlets of the ID fans on both sides of the boiler. After filtering and conditioning, the gas was led to chemiluminescent monitors for NO_x concentration measurement and to paramagnetic devices for O_2 determination. No rigorous investigations of the accuracy of the individual measurements were made during these tests. However, experience suggests that the NO_x data are expected to be accurate to ±15 vpm at the 400vpm level and the O_2 to about ±0.2%O_2. Simultaneously, an 'across-the-duct' infra-red monitor was commissioned, calibrated and tested. This device was found to operate adequately and is now the primary means of emission measurement, providing continuous data of NO_x concentrations on an hourly average basis during Phase 3. This instrument is being compared regularly with the conventional system to maintain confidence in the results.

Sonic pyrometry (2) was used in these trials on the modified boiler to measure furnace gas temperatures. This technique, which utilizes the temperature dependence of the speed of sound in a gas, enables determinations to be made of both the mean temperature and the temperature distribution in a plane across the furnace. One side of the Fiddler's Ferry No.1. unit was instrumented in a horizontal plane immediately below the nose of the furnace. Data previously obtained during a series of short, well-controlled test periods on an identical boiler with standard burners provided a useful comparison.

OPTIMIZATION OF NO_x EMISSIONS ON THE MODIFIED BOILER.

Overfire Air.

Short term tests were carried out to examine the effect of different amounts of overfire air on emissions with two different mill groups in service. With the top mill operating, and with both overfire air dampers shut, the NO_x emission was 433 vpm, but this concentration fell to 395 vpm with the small overfire air port open and to 366 vpm with the large overfire air port open. With the maximum overfire air flow (both dampers open) a concentration of 356 vpm was recorded, representing an overall reduction of about 18%. These data are illustrated in Figure 2. A similar pattern was observed when the bottom five mill groups were put into service and the quantity of overfire air adjusted, the data in Figure 2 indicating a fall of about 20% in NO_x emissions. There were no overfire air ports on the 'baseline' boiler so that a true comparison of overfire air effectiveness was not possible. However, it was possible to simulate the introduction of overfire air by opening the secondary air dampers on the top mill without any fuel flow. Typical results from this exercise are shown in Figure 2. It should, however, be recognized that, in this mode of operation, the lower part of the furnace was operating sub-stoichiometrically and the tests of this type were, therefore, intended to be indicative of trends rather than as precursors to long-term operation.

Effect of Secondary Air Yaw Position on NO_x Emissions.

The secondary air yaw position on the modified boiler is offset by 17.5° from the coal injector centreline towards the side walls of the furnace with a possible adjustment to alter this angle by ±7.5°. However, during tests aimed at determining the effect of altering this parameter on boiler performance, it was found that it made no significant change in NO_x emissions. Interestingly, the sonic pyrometry measurements also indicated that altering the yaw of the secondary air offset did not affect either the mean or the peak gas temperatures at the furnace nose. It was suggested that the higher the offset angle, the greater the separation between the fuel-rich and the fuel-lean regions and, therefore, the lower the likelihood of reducing regions occurring at the furnace walls and promoting corrosion of the furnace wall tubes. Thus, the offset was maximized at 25° for the long-term tests.

The Effect of Overfire Air Tilt Angle on NO_x Emissions.

The overfire air ports can be tilted to an angle of +10° above that of the burners and the effect of this adjustment on NO_x levels was investigated. The results showed that no measurable change in NO_x emissions was apparent when the overfire air tilt was increased to 10° greater than the burner tilt. During these tests, the burner tilt was maintained in the horizontal position with the top five mills in service. It was noted that this alteration in overfire tilt affected the gas temperature at the furnace nose, causing an increase of about 40K. It is, therefore, possible to speculate that any decrease caused by the separation of the substoichiometric and overfire injection regions was counteracted by an increase in thermal NO_x production. This change was, however, only made with the top five mill groups in service and it is possible that elevating the overfire air tilt may have a slightly different effect if the lower five were in service due to the greater volume of the substoichiometric region in this case. For long term operation, the overfire air tilt angle was permanently set at 10° above that of the main burners.

COMPARISON OF EMISSIONS FROM MODIFIED AND UNMODIFIED BOILERS.

When comparing the NO_x emissions from different tests or boilers, it is necessary to take into account the effect of furnace oxygen concentrations as well as the effects of air inleakage. In this particular case, this difficulty is considerably eased by the fact that the airheater leakage (8%) and the precipitator leakage (4%) on both the modified and unconverted units were almost identical. Thus, assuming that the tramp air leakage on both boilers was similar, identical measurements of oxygen levels at the ID fan will represent very similar furnace oxygen values. It is, therefore, valid to compare NO_x levels at comparable operating conditions to assess the effectiveness of the modifications to the combustion system.

NO_x Emissions at Different Oxygen Levels.

Figures 3 and 4 show a comparison of the NO_x emissions from the modified and unmodified units at different excess air levels with the top mill in and out of service respectively. In both cases, an almost constant difference of about 150-200 vpm is apparent over the excess air range covered. Clearly, the percentage difference is greatest at the lowest oxygen level. In both cases, a linear relationship is obtained with increasing NO_x production as the excess air levels are raised. NO_x concentrations increase by about 70 vpm for every 1% increase in O_2 as measured at the ID fan discharge. It is noteworthy that the highest emissions are obtained with the top mill in service, this observation correlating well with the sonic pyrometry measurements of both peak and mean temperatures.

An alternative method of comparing the NO_x emissions from the two burner configurations is to attempt to correlate the concentration with the fuel:air ratio in the lower part of the furnace. This method simply reflects the fact that the amount of fuel-nitrogen oxidised to NO is directly related to the oxygen concentration in the primary combustion zone. Figure 5 shows the results of this exercise for the particular case of the bottom five mills in service with zero or negative burner tilt. Similar effects are noted with data for the other mill groups. Furnace stoichiometries have been calculated using oxygen values measured at the ID fan outlets and corrected for airheater and precipitator inleakage. The accuracy of the stoichiometry data could be improved by inclusion of accurate data on tramp air inleakage although the value of the correlation is unlikely to be significantly affected.

The importance of these plots lies in the fact that the experimental information acquired during operation with overfire air correlates well with the data obtained under non-staged conditions for both the modified and unmodified boilers. A clear trend of decreasing NO_x with increasing quantities of overfire air may be derived from this Figure. It is also possible to separate the effects of the overfire air from that of the production of the rich fireball, since the difference between the two sets of data is approximately 80 vpm and this may be attributed solely to the secondary air offset (yaw) in the modified system and the restriction of secondary air around the coal ports. This difference is approximately constant over the whole range of stoichiometry tests and indicates that the decrease in NO_x by overfire air in the modified boiler is similar to that achieved on the unmodified boiler by injecting air through the top row of burners.

Effect of NO_x Emissions when Burner Tilts are Altered.

On the unmodified boiler, increasing the burner tilt to +15° increased the NO_x emission significantly. This effect was not apparent on the converted unit, the results of altering the burner tilts, with overfire air tilt at 10° above the burner tilts, being shown in Figure 6. With the top mill in service, no significant changes in concentration were apparent when the tilts were raised from -15° to +15°. When the top mill was out of service, an increase in tilt from 0° to 15° resulted in only a small increase in NO_x.

Effect on NO_x Levels of Different Boiler Loads.

Tests were carried out to determine NO_x emissions at different boiler loads. At low loads, the excess air level is significantly increased in order to maintain the correct balance of steam generation in the furnace and this effect tends to distort the interpretation of the data. When corrected to 3%O_2, there was no apparent trend of NO_x with load, indicating that the NO_x emission per unit MW generated tends to increase as the fuel throughput is lowered. In addition, at low loads (<400MW(e)) the secondary air dampers have to be pulled in to maintain an acceptable windbox pressure and, although it was just possible to conduct a test at this condition, it was decided that for routine operation at low loads, the overfire air dampers should be shut. It should be emphasised that this inability to operate at low load in the desired low-NO_x mode is due to the, site-specific, retrofit configuration of the burner system installed, it being possible to construct new plant without this feature.

Boiler Efficiency and Carbon Burnout.

Before the tests, a 48 point velocity and temperature survey of each combined airheater outlet was undertaken in order to identify a single-point representative of the bulk gas in each combined outlet duct. At these points, dust samples were taken isokinetically during each test period and their carbon contents subsequently determined.

No significant changes in the carbon-in-ash were detected when the overfire air dampers were closed. However, a significant increase (of around 2%) was noted in the ashes from both sides of the boiler when the burner tilts were lifted to the +15° position. Notwithstanding this effect, it is clear that the excess air level has the dominant effect upon carbon-in-dust, as illustrated in Figure 7 where an approximately linear relationship is exhibited between carbon-in-ash and the excess air.

Under standard operating conditions, the efficiency of the boiler was calculated to be 92.91% ± 0.08%, a similar figure to that obtained on the unmodified unit. The effect of excess air on boiler efficiency is evident from inspection of Figure 8 which indicates that at the lowest excess air the increase in unburnt losses is more than offset by the decrease in energy loss in the flue gas.

Precipitator Performance.

In theory, the low-NO_x burner installation could affect the precipitator performance detrimentally by one or more of three mechanisms. Firstly, a substantial increase in carbon-in-ash might lower the dust resistivity sufficiently to decrease precipitation of carbon-rich particles. Secondly, any increase in total flue gas volume and hence increased velocities through the precipitator would decrease particle residence times and lead to increased dust emissions. Thirdly, changes in the initial stoichiometry in the furnace might affect the formation of SO_3 and hence alter the surface resistivity of the dust particles.

The flue gas volumes measured during the tests on the modified unit were almost identical to those measured during the 'baseline' tests. This was, of course, expected since the low-NO_x system is designed to redistribute the total air, not to increase it. As shown above, no increase in carbon-in-ash was noticed after the fitting of the new burner system and the measured dust emission from the converted boiler at full-load was comparable to that from the unmodified unit. It was, therefore, concluded that the presence of the low-NO_x burner system had no significant effect on either dust emissions or on precipitator performance.

Furnace Atmosphere Measurements.

Measurements of furnace atmospheres have been made both before and after the introduction of the low-NO_x system in order to assess any changes due to the burner alterations and the redistribution of the secondary air. These were carried out since previous investigations in coal-fired boilers of similar design to that considered here have indicated that strongly reducing atmospheres (CO concentrations up to 12% vol) could be present close to some areas of the boiler walls and that these regions were usually associated with high corrosion rates.

Measurement of the composition of the gases in the proximity to the boiler walls were made after the unit's long term operating parameters had been defined. As mentioned above, these were selected primarily on the basis of the lowest achievable NO_x emission level although it must also be recognized that the position of the secondary air yaw, which did not appear to affect NO_x, was fixed at the maximum (25°) in order to provide conditions thought to be most likely to minimize corrosion.

It was found that, from the evidence of the short testing periods, furnace wall conditions on the modified unit were much improved on those previously measured on unconverted units of this type. Oxidising conditions were nearly always present in the areas considered although there were some indications of slag build-up in some regions which might suggest the occasional period of reducing conditions. A complete coverage of the furnace walls was not carried out so that it is currently not possible to determine whether the area of high corrosion has been moved by the new burner configuration. Such an evaluation can only be made by a rigorous NDT measurement of tube wall thickness, and this will not be performed until 1988 when the next statutory boiler inspection will be carried out.

LONG TERM MEASUREMENTS.

The NO_x performance of the low-NO_x system is being continuously assessed during the three year trial by the use of an across-duct infra-red NO_x monitor in the stack. Measurements of NO_x, O_2 and boiler load, taken at five minute intervals, are combined into half-hourly averages and stored on magnetic tape for subsequent analysis. Typical data obtained in the first six months of operation are shown in Figure 9 for a total of 2178 hours of operation for which the mean load was in excess of 450MW (gen), it being observed that the mean NO_x concentration (under the operating conditions of 6% O_2 in the stack) was around 337 vpm. Clearly, such a figure represents the average of all the mill groupings and burner tilt combinations used during the test period and is similar to that indicated from analysis of the data presented in Figures 3 and 4 for the short term characterization tests. Thus it is clear that the NO_x reduction described above in the short, post modification tests are being sustained during day-to-day operation.

CONCLUSIONS.

A 500MW(e) tangentially-fired boiler at Fiddler's Ferry Power Station was retrofitted with the 'rich-fireball' low-NO_x system during the course of a normal boiler survey schedule. The impact of this modification upon the NO_x emissions and efficiency of the unit has been examined in the course of a dedicated trial programme. Preliminary results indicate that the converted boiler emits, depending on the mill groups in service, between 31 and 38% less NO_x than a similar, unmodified unit. This has been accomplished without any measurable change in boiler efficiency or precipitator efficiency. Long-term tests are continuing in order to provide data concerning the effect of the 'rich-fireball' system on furnace corrosion.

ACKNOWLEDGEMENTS.

The authors wish to express their gratitude to the Station Manager and staff of Fiddler's Ferry Power Station for their assistance in all stages of the execution of this project.

This paper is published with the permission of the Central Electricity Generating Board.

The work described in this paper was not funded by the U.S. Environmental Protection Agency and therefore the contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

REFERENCES.

1. Kokkinos, A., Donais, R.E., McCartney, M.S. and McElroy, M.W., (1982). 'Low NO_x System for Tangentially Fired Utility Boilers'. Paper Presented at the 1982 Joint Symposium on Stationary Combustion NO_x Control, November 1982.

2. Green, S.F. and Woodham, A.U., (1983). 'Rapid Furnace Temperature Measurement by Sonic Pyrometry'. Paper Presented to the 7th Members Conference of the International Flame Research Foundation, IJmuiden, May, 1983.

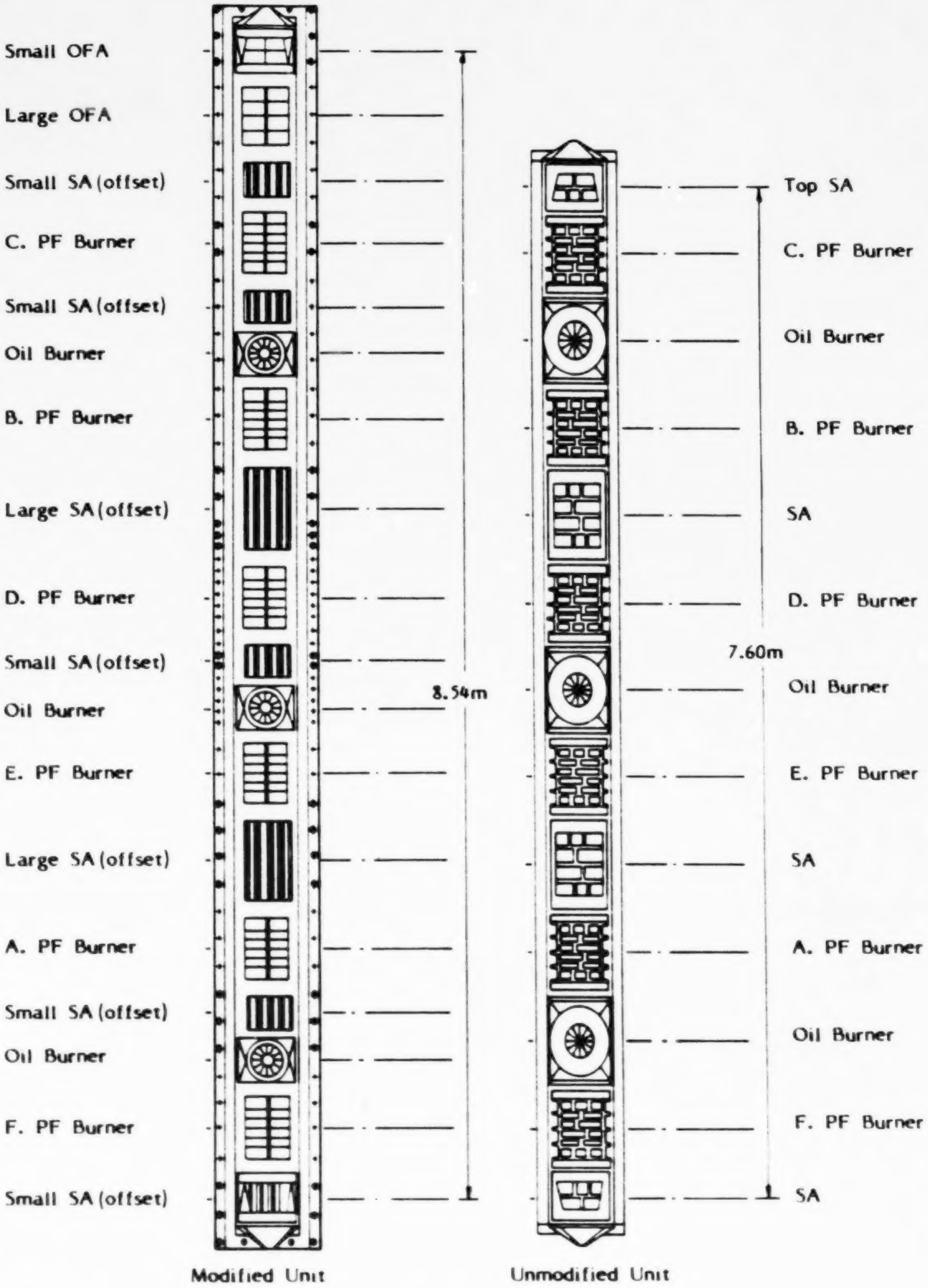

Small OFA
Large OFA
Small SA (offset)
C. PF Burner
Small SA (offset)
Oil Burner
B. PF Burner
Large SA (offset)
D. PF Burner
Small SA (offset)
Oil Burner
E. PF Burner
Large SA (offset)
A. PF Burner
Small SA (offset)
Oil Burner
F. PF Burner
Small SA (offset)
8.54m
Modified Unit
Top SA
C. PF Burner
Oil Burner
B. PF Burner
SA
D. PF Burner
7.60m
Oil Burner
E. PF Burner
SA
A. PF Burner
Oil Burner
F. PF Burner
SA
Unmodified Unit

FIGURE 1. SCHEMATIC OF MODIFIED AND UNMODIFIED BURNER BOXES.

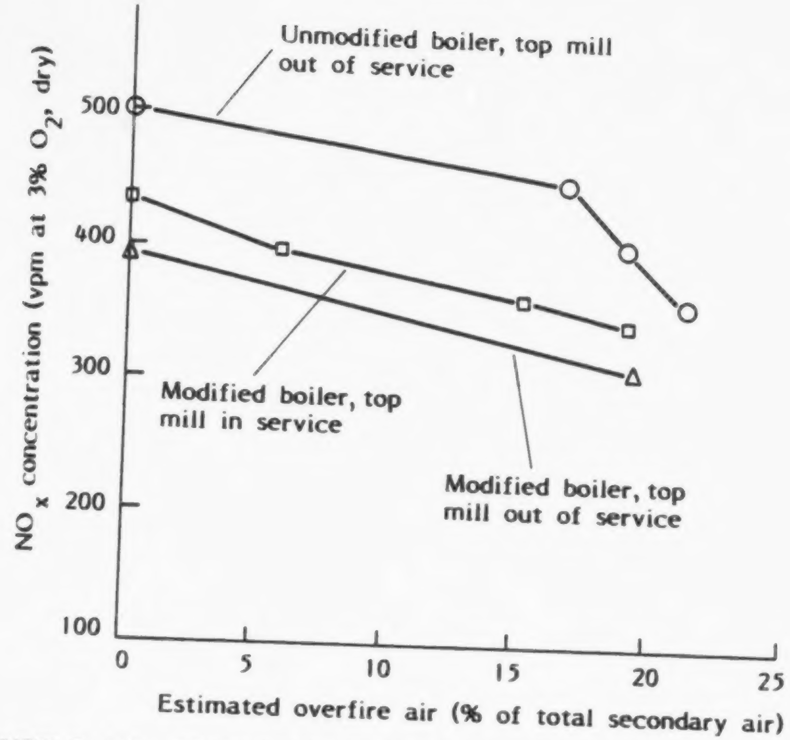


FIGURE 2. NO_x LEVELS AS A FUNCTION OF PERCENTAGE OVERFIRE AIR FOR MODIFIED AND UNMODIFIED BOILERS.

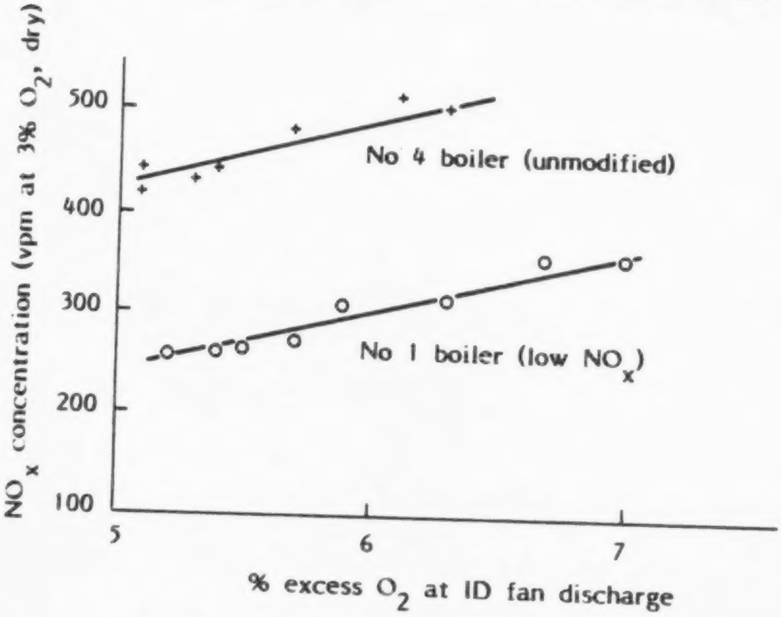


FIGURE 3. COMPARISON OF NO_x EMISSION FROM LOW NO_x BOILER (No 1) AND UNMODIFIED BOILER (No 4) AT DIFFERENT EXCESS AIR LEVELS (TOP MILL OUT OF SERVICE).

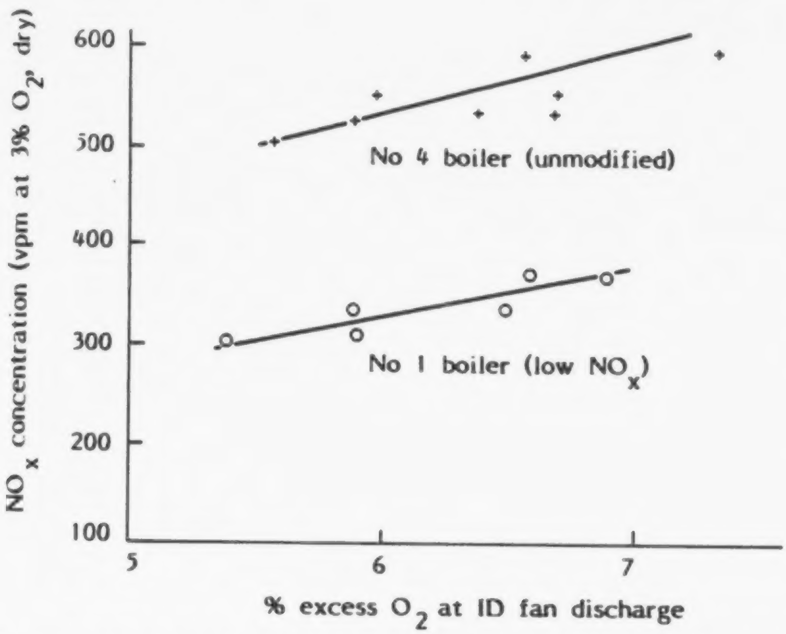


FIGURE 4. COMPARISON OF NO_x EMISSIONS (CORRECTED) FROM LOW NO_x BOILER (No 1) AND UNMODIFIED BOILER (No 4) AT DIFFERENT EXCESS AIR LEVELS (TOP MILL IN SERVICE).

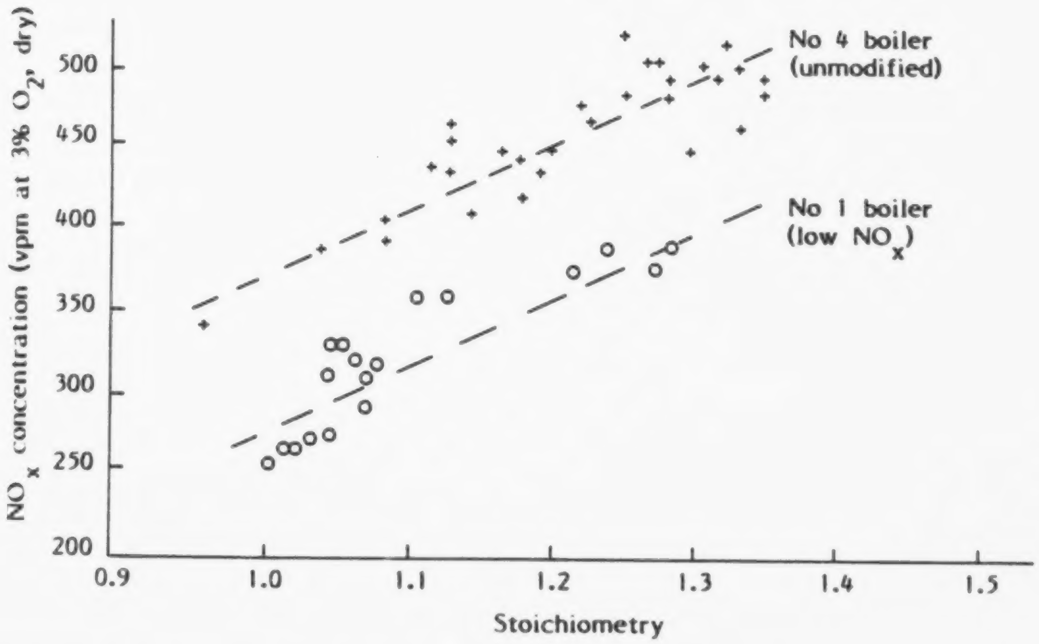


FIGURE 5. PLOT OF NO_x EMISSION AGAINST ESTIMATED STOICHIOMETRY IN LOWER PARTS OF FURNACE (TOP MILL OUT OF SERVICE).

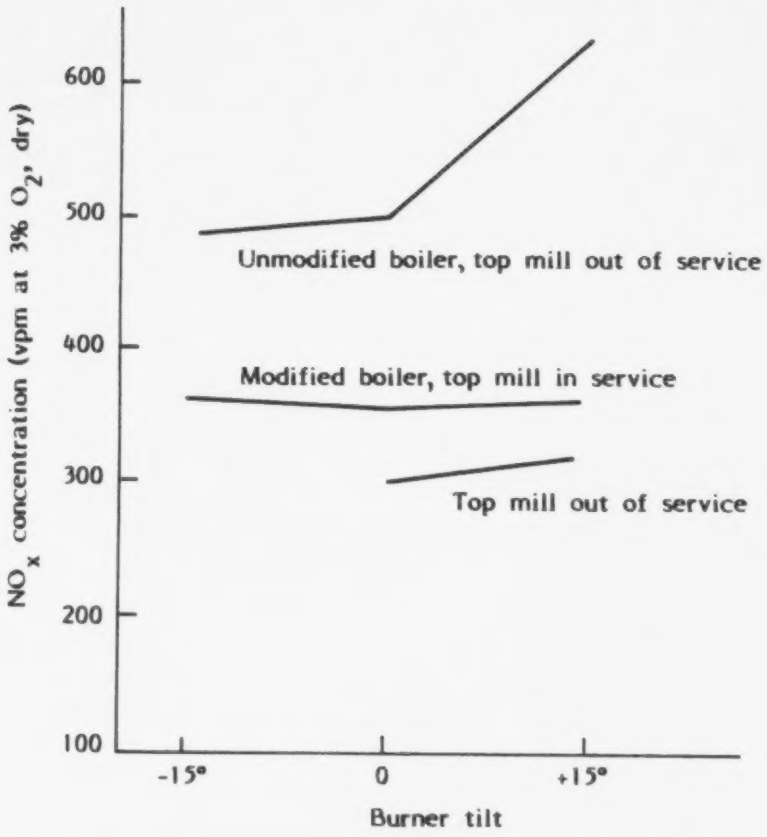


FIGURE 6. NO_x CONCENTRATIONS AS A FUNCTION OF BURNER TILT FOR MODIFIED AND UNMODIFIED BOILERS.

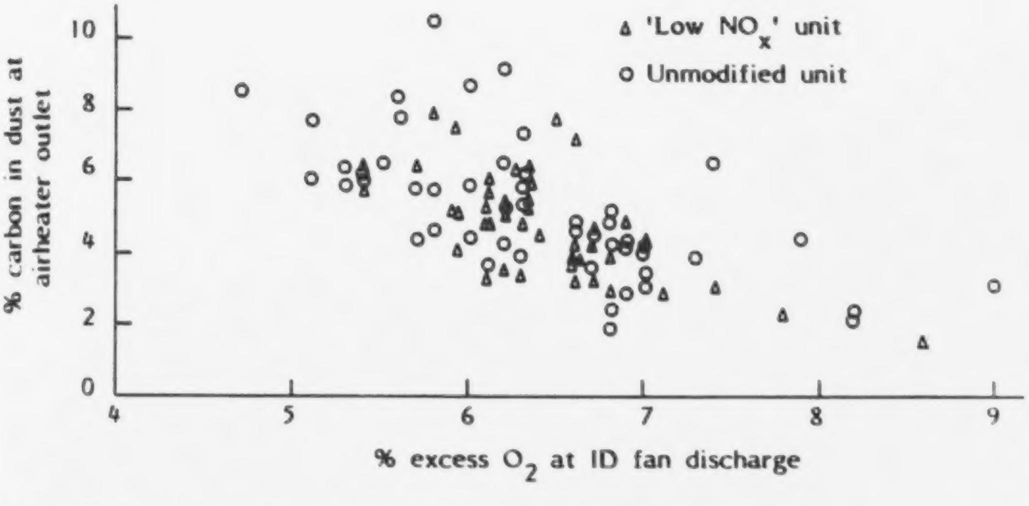


FIGURE 7. VARIATION OF CARBON IN DUST WITH EXCESS O_2 AT ID FAN DISCHARGE

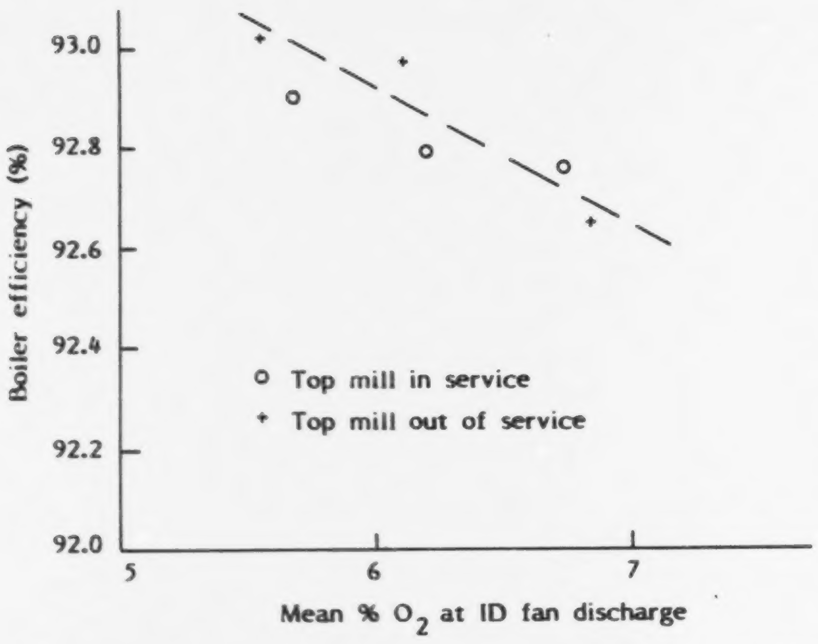


FIGURE 8. EFFECT OF EXCESS AIR LEVEL ON BOILER EFFICIENCY (479 to 490 MW)

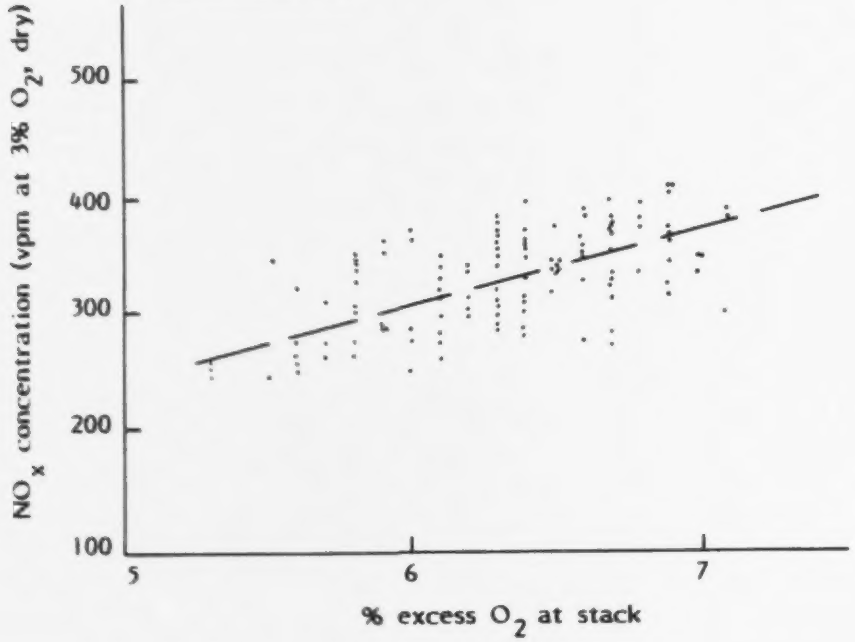


FIGURE 9. VARIATION OF DAILY MEAN NO_x EMISSION WITH DAILY MEAN EXCESS O_2.

APPLICATION OF MITSUBISHI "ADVANCED MACT" IN-FURNACE NOx REMOVAL PROCESS AT TAIO PAPER CO., LTD. MISHIMA MILL NO. 18 BOILER

M. Araoka
Mitsubishi Heavy Industries, Ltd.
Boiler Engineering Department
Power Systems Engineering Division
Power Systems Headquarters
Shin-Tamachi Bldg. 34-6, Shiba 5-Chome
Minato-ku, Tokyo, Japan

A. Iwanaga
Mitsubishi Heavy Industries, Ltd.
Manager
No.2 Land Boiler Designing Section
Nagasaki Shipyard & Engine Works
1-1, Akunoura-machi, Nagasaki, Japan

M. Sakai
Mitsubishi Heavy Industries, Ltd.
Manager
Power Systems Engineering Research & Promotion Laboratory
Nagasaki Research and Development Center
180 Koyakimachi Nishisonogi-gun, Nagasaki, Japan

ABSTRACT

Mitsubishi Heavy Industries, Ltd. has been engaged in the research and development of new technology concerning the prevention of air pollution. In the field of low NOx combustion technology, we have already developed and utilized many countermeasures , for example, super low NOx PM burners and MACT system which have already been introduced at the former symposiums.

This time, we have successfully developed and put into practical use the "Advanced MACT" system. This paper introduces the outline of this "Advanced MACT" system and its application and operating experience at Taio Paper Co., Ltd., Mishima Mill No. 18 Boiler.

INTRODUCTION

Governmental regulation on NOx emission in Japan was first issued in 1973 and has become severer by its four times renewal and allowable NOx emission for coal fired power plants which will commence commercial operation after 1987 is 200 ppm as shown in Figure 1. Local government, however, always demands much lower NOx emission of 180 ppm for example at the inlet of SCR system and 60 ppm at the outlet of stack. MHI has paid very large efforts to develop firing techniques of low NOx emission well below the requirements by the customer as shown in Figure 2. Namely, as for coal fired boiler, since 1976 when we started the development of SGR burner, we have produced and utilized many epochmaking low NOx firing system one by one - Coal PM Burner in 1981,*1 Coal MACT in 1984.

MACT system, which was presented at the former symposium at Boston in 1985*2 is an in-furnace NOx removal technology by utilizing the decomposition of NOx by hydrocarbon in a very high temperature zone. In this system, upper burner and additional air port are installed besides the main burner and combustion in two stages and NOx reduction process occur in the furnace. Although MACT is applicable to all kinds of fossil fuels, in case of coal fired boiler, the duct work and coal piping work for upper burner make the boiler arrangement rather complicate. Therefore oil has been used for upper burner fuel.

Since MHI has put MACT system into practical use, it has made more efforts to improve this point and has developed "Advanced MACT" system. In this "Advanced MACT" system, by controlling the amount of air in the main burner zone, overfire air and additional air, nearly the same De-NOx effect is realized by the hydrocarbon which is introduced to the furnace through the main burner and kept un-oxidized. Therefore it becomes possible to remove the upper burner and the boiler arrangement is simplified. In this paper, the outline of the technology and the field results applied to 350 t/h industrial boiler are introduced.

CONCEPT OF "ADVANCED MACT" SYSTEM

GENERAL

As well as the original MACT (Mitsubishi Advanced Combustion Technology), "Advanced MACT" is an in-furnace NOx removal process based on the principle of NOx reduction by hydrocarbons in the high gas temperature zone. The difference from the original MACT in the point of the apparatus is that upper burner (UB) is removed and hydrocarbon injected through UB is substituted by the unburnt hydrocarbon which is injected through main burner.
The advantages of MACT are also those of "Advanced MACT" and "Advanced MACT" system has one more advantage that the duct and fuel pipe arrangement are simple and more economical. The advantages of "Advanced MACT" system are;

(1) Applicable to all fossil fuels - coal is most preferable
(2) Little additional operating cost
(3) No emission of additional undesirable substances to the environment
(4) Boiler efficiency and flue gas quantity unchanged
(5) Free combination with other NOx reduction system
(6) Easy operation and control
(7) More simple duct and fuel pipe arrangement

MECHANISM OF NOX REDUCTION BY "ADVANCED MACT"

Burner Arrangement

Figure 3 shows the concept of burner arrangement of "Advanced MACT" system. As for the main burner, low NOx coal PM burners are applied and overfire air nozzles (OFA) are installed just above the main burner and Additional Air nozzles are installed above the OFA nozzle with a suitable distance. OFA nozzles and AA nozzles are equipped with tilting device and the direction of air injection is adjustable.

Combustion and NOx Reduction Process

Through the fundamental laboratory test, it was found that the following conditions are required to promote the de-NOx reaction with the help of hydrocarbon.

(1) Higher reaction temperature is desirable (preferably above 1,200°C as shown in Figure 4.

(2) Required residence time is greater than 0.1 sec. as shown in Figure 5.

(3) NO decomposition rate depends on air ratio and it should be between 0.2 and 1.0 as shown in Figure 6.

(4) For combustion completion stage, NOx formation is smaller if O_2 injection is divided into several stages (practically two stages) as shown in Figure 7.

Hereinafter, how MHI satisfied the above conditions are explained with the chemical reaction occured in the furnace.

(1) As PM burner is installed, NOx generation at main burner zone is kept at low level.

(2) The amount of air at the main burner zone is limited less than theoretically required and air lean combustion is obtained. Air lean combustion is another factor for decreasing the NOx generation. But too much lack of air must be avoided because it will introduce not only the increase of unburnt carbon in fly ash but also reductive corrosion of water wall tube. Therefore the amount of air at burner zone should be selected suitably.

(3) As the combustion at main burner zone is executed under lean air condition, all O_2 injected through main burner is consumed and reductive atmosphere exists between the exit of top burner and OFA port. This reductive atmosphere decomposes the NOx generated at main burner zone. This decomposition reaction occurs in a very short time (less than 0.1 second) and high reduction rate is attained.

(4) The chemical reaction equation in the NOx decomposing zone is summarized as follows.

$$\mathrm{NOx} + \mathrm{O_2} + \mathrm{CnHm} \begin{array}{l} \longrightarrow \mathrm{N_2} + \mathrm{H_2O} + \mathrm{CO} \\ \searrow \mathrm{NHi} + \mathrm{H_2O} + \mathrm{CO} \end{array}$$

As shown above some NOx is decomposed to N_2, but some other NOx is changed to another type of N-compound (NHi).
The amount of generated NHi depends on the NOx concentration. It decreases as the NOx concentration decreases, but the conversion rate of NOx to NHi, on the contrary increases as the NOx concentration decreases.

air nozzles (OFA) are installed just above the main burner and Additional Air nozzles are installed above the OFA nozzle with a suitable distance. OFA nozzles and AA nozzles are equipped with tilting device and the direction of air injection is adjustable.

Combustion and NOx Reduction Process

Through the fundamental laboratory test, it was found that the following conditions are required to promote the de-NOx reaction with the help of hydrocarbon.

(1) Higher reaction temperature is desirable (preferably above 1,200°C as shown in Figure 4.

(2) Required residence time is greater than 0.1 sec. as shown in Figure 5.

(3) NO decomposition rate depends on air ratio and it should be between 0.2 and 1.0 as shown in Figure 6.

(4) For combustion completion stage, NOx formation is smaller if O_2 injection is divided into several stages (practically two stages) as shown in Figure 7.

Hereinafter, how MHI satisfied the above conditions are explained with the chemical reaction occured in the furnace.

(1) As PM burner is installed, NOx generation at main burner zone is kept at low level.

(2) The amount of air at the main burner zone is limited less than theoretically required and air lean combustion is obtained. Air lean combustion is another factor for decreasing the NOx generation. But too much lack of air must be avoided because it will introduce not only the increase of unburnt carbon in fly ash but also reductive corrosion of water wall tube. Therefore the amount of air at burner zone should be selected suitably.

(3) As the combustion at main burner zone is executed under lean air condition, all O_2 injected through main burner is consumed and reductive atmosphere exists between the exit of top burner and OFA port. This reductive atmosphere decomposes the NOx generated at main burner zone. This decomposition reaction occurs in a very short time (less than 0.1 second) and high reduction rate is attained.

(4) The chemical reaction equation in the NOx decomposing zone is summarized as follows.

$$\mathrm{NOx} + O_2 + \mathrm{CnHm} \begin{array}{l} \longrightarrow N_2 + H_2O + CO \\ \searrow \mathrm{NHi} + H_2O + CO \end{array}$$

As shown above some NOx is decomposed to N_2, but some other NOx is changed to another type of N-compound (NHi).
The amount of generated NHi depends on the NOx concentration. It decreases as the NOx concentration decreases, but the conversion rate of NOx to NHi, on the contrary increases as the NOx concentration decreases.

(5) The reverse reaction from NHi to NOx occurs easily if O_2 is supplied. As this NOx generation reaction has such characteristics as shown in Figures 8 to 10, low NOx and complete combustion is obtained using this fact. Namely, the conversion rate of NHi to NOx decreases as the O_2 content decreases. Therefore by introducing the required air for complete combustion to furnace in two stages like OFA port and AA port instead of one stage and keeping the O_2 content in-furnace at low level, the re-generation of NOx is minimized.

NHi is decomposed to N_2 in the reductive atmosphere where O_2 does not exist ($NHi \rightarrow N_2 + H_2$) and this N_2 is not easy to turn NOx even if O_2 is supplied afterward.
To promote this reaction, it is required to keep the gas temperature high enough and residence time long enough as shown in Figures 9 and 10.
To have enough residence time in reductive gas, the distance from main burner to location of OFA nozzle and AA nozzle is decided using the gas flow simulation by FEM method as shown in Figure 11.

AA nozzle should be located with some distance from the main burner because the conversion rate from NHi to NOx decreases as the gas temperature decreases as shown in Figure 12. Further, to decrease the unburnt carbon in fly ash as well as NOx, tilting device is installed and it is adjusted at the combustion test.

INVESTIGATION AT TEST FURNACE

The "Advanced MACT" system as well as other low NOx combustion technology, was investigated at our laboratory using the 3 t/h coal firing test furnace in Nagasaki Research and Development Center.

DESCRIPTION OF TEST FACILITIES

Figure 13 shows the cross-sectional view of the test furnace. The wall of the furnace is of water cooled double walled construction, and this test furnace was constructed to simulate a 700 MW coal fired boiler.
Part of its inner surface is lined with refractory to keep the furnace temperature at the same level of the actual boiler so that the state of self ignition of injected coal, degree of NOx formation, the level of flame temperature and the percent of unburnt carbon in fly ash in the actual boiler are simulated.
Combustion air is supplied by a forced draft fan to the burner after being heated to about 300 °C by air preheater as is usually the case with actual boilers. A part of the air is directly injected into the furnace as overfire air through the OFA ports and as additional air through the AA ports, located on the furnace wall above the burner. Another part of the air is used as primary air carrying pulverized coal. It is branched off and mixed with cold air to a proper temperature and is led to the outlet of the pulverized coal bin (PC bin) and passes to the burner carrying pulverized coal fed through the coal feeder.

A heavy oil line and a LPG line are also provided to the test furnace, the former is for the start-up burner and the latter is for the ignitor.

The combustion gas leaving the furnace is cooled by the gas cooler and passes through the cyclone separator separating fly ash and then enters the air preheater. After heating air in the air preheater, the gas leaves it at about 150 °C to the bag filter where it is further separated remaining fly ash and then it is discharged to the atmosphere from the stack.

A part of flue gas is recirculated by the gas recirculation fan (GRF) and injected into the furnace, partly through the SGR nozzles of the burner, and partly mixed with secondary air (GM-Gas Mixing).

Flue gas is sampled for analysis from the gas duct at the outlet of the furnace. Fly ash is sampled from the cyclone separator and from the bag filter separately. After measuring the amount of unburnt carbon in each sample, the weighted mean is calculated to represent the percent of unburnt carbon in fly ash. Flame temperature is measured with an optical pyrometer and heat flux to the furnace wall is measured with a heat flow meter.

TEST RESULTS

The test results using the test furnace are summarized in the Figures 14 to 16, and the fuel analysis results of used coal are listed in Table 1.

As shown in Figure 14, NOx emission decreases as AA ratio increases and unburnt carbon in fly ash is not affected so long as AA ratio is around 30%. AA has more NOx reducing effect than OFA as shown in Figure 15. In this figure abscissa shows the summation of AA ratio and OFA ratio. When the AA + OFA ratio is the same, NOx emission is smaller in case AA ratio is greater. Figures 16 summarizes the effect of "Advanced MACT". By injecting about 30% of total air through additional air port, NOx emission is reduced about 30% without increasing the unburnt carbon in fly ash.

APPLICATION OF "ADVANCED MACT" SYSTEM AT 350 t/h INDUSTRIAL BOILER

DESIGN CONDITIONS AND CONSTRUCTION OF BOILER AND BURNER

The first application of this "Advanced MACT" system to commercially operated boiler is at Taio Paper Co., Ltd., Mishima Mill No. 18 Boiler. It is a coal fired natural circulation industrial boiler with the maximum evaporation of 350 t/h and commenced commercial operation in May 1986. The design conditions of this boiler is summarized in Table 2. Figure 17 shows the sectional side view. It is designed to fire imported coal - mainly Australian coal and South African coal - and Japanese coal as shown in Table 3.

N content in fuel is around 2%. Guaranteed NOx emission is 150 ppm as of 6% O_2. EP (Electrostatic Precipitator) and FGD (Flue Gas Desulfurization system) are installed, but no SCR system is installed and this value has to be achieved by low NOx PM burner and "Advanced MACT" system.

Figure 18 shows the burner windbox arrangement. Four windboxes are installed at each corner of the furnace and air is blown in tangentially. Main burner is constructed of four levels of coal PM burners and two levels of supporting oil burners. OFA is installed just above the top coal burner and AA is installed above the OFA with a suitable distance.

Figure 19 shows the air and gas flow diagram. This boiler is installed the additional air fan (AAF) which boosts up the air for OFA and AA. The capacity of AAF is about 35% of total air. This is because the OFA and AA must be injected to center of the fireball with higher velocity than the air at main burner zone. Of course at some other industrial boilers with "Advanced MACT" system, this AAF is removed and FDF has enough head.

OPERATING RESULTS

This boiler was first lighted off in April 1986 and the test for performance confirmation was executed in May 1986. Table 3 shows the analysis of coal for design and at combustion test. Figure 20 shows the relation between NOx and unburnt carbon in fly ash to O_2 at economizer outlet obtained from the combustion test of actual boiler with the parameter of speed of rotary separator of coal pulverizer and burner tilting.

As well as the other boiler's cases, NOx emission decreases and unburnt carbon in fly ash increases as O_2 decreases. In this boiler, 2.5% O_2 is finally selected because unburnt carbon in fly ash increases sharply if O_2 at economizer outlet decreases less than this value.

Figure 21 shows the relation between NOx and unburnt carbon in fly ash to boiler load. Round mark (○) shows the recommended operating condition and triangle (△) and square mark (□) show the minimum NOx operating condition with less than 5% of unburnt carbon in fly ash.

Estimated NOx emission using conventional coal PM burners is 200 ppm. As shown in this figure, NOx is kept below 150 ppm and unburnt carbon in fly ash below 5% through all load. Minimum NOx at full load is 139 ppm with 4.4% of unburnt carbon in fly ash. This results shows the effect of "Advanced MACT" is about 30% which shows good agreement with our expectation through test furnace results. It is not too much to say that the guaranteed condition was satisfied with margin.

Figure 22 shows the relation between NOx emission and unburnt carbon in fly ash. There is a negative correlation between them and recommended operating condition was selected to satisfy the both conditions. Unburnt carbon in fly ash decreases by increasing the fineness of pulverized coal with higher rotary separator speed.

CONCLUSION

MHI has developed many countermeasures for environmental protection and its latest one for low NOx combustion technology is "Advanced MACT" system. It has already applied to many industrial boilers including Taio Paper Co., Ltd. Mishima Mill No.18 boiler as shown in Table 4, and all of them are operated successfully and have got good reputations. Though no utility boilers with "Advanced MACT" is operated at present, two coal fired boilers which will commence commercial operation in a few years are now designed to install this "Advanced MACT" system. MHI does really hope the prevalence of "Advanced MACT" system and every people can enjoy the profit in the point of environmental protection, low operating and initial cost, and victory in technology.

The work described in this paper was not funded by the U.S. Environmental Protection Agency and therefore the contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

REFERENCE

1. T. Namiki Application of Pulverized-coal-Fired Low-NOx PM Burner for steam generator, Mitsubishi Boiler Bulletin, MBB 85051E, May 1985, presented at Joint Symposium on Stationary Combustion NOx Control, May 6-9, 1985 Boston, Massachusetts, U. S. A.

2. N. Murakami Application of The MACT In-Furnace NOx removal process coupled with a Low-NOx SGR Burner, Mitsubishi Boiler Bulletin, MBB 85052E, May 1985, presented at Joint Symposium on Stationary Combustion NOx Control, May 6-9, 1985 Boston, Massachusetts, U. S. A.

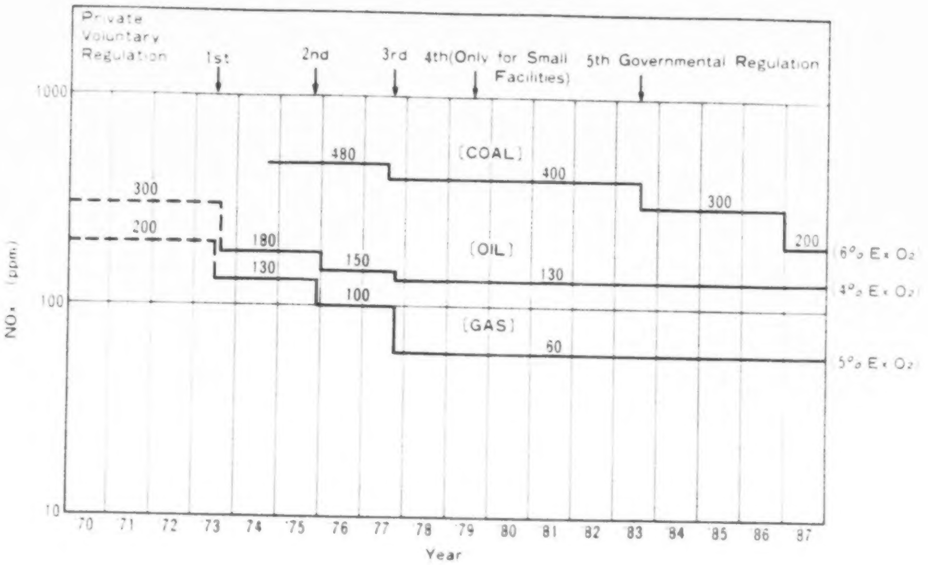


Figure 1. Trend of NOx Governmental Regulation for New Large Plants in Japan

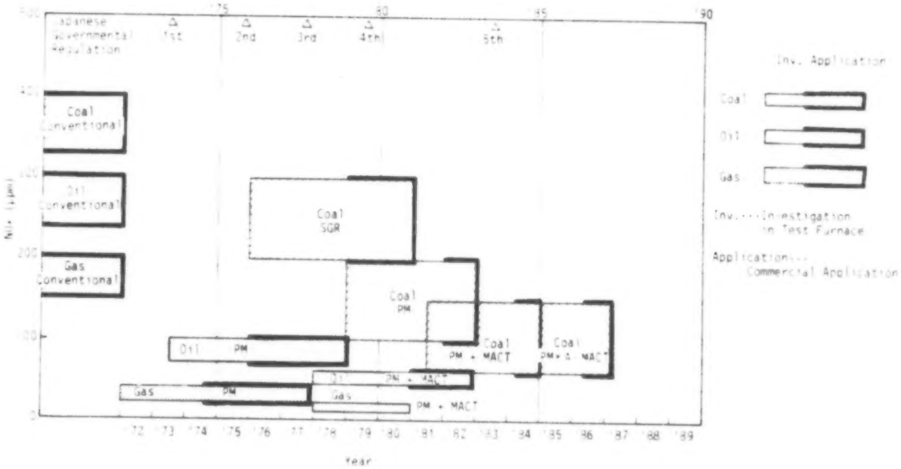


Figure 2. History of Low NOx Technology

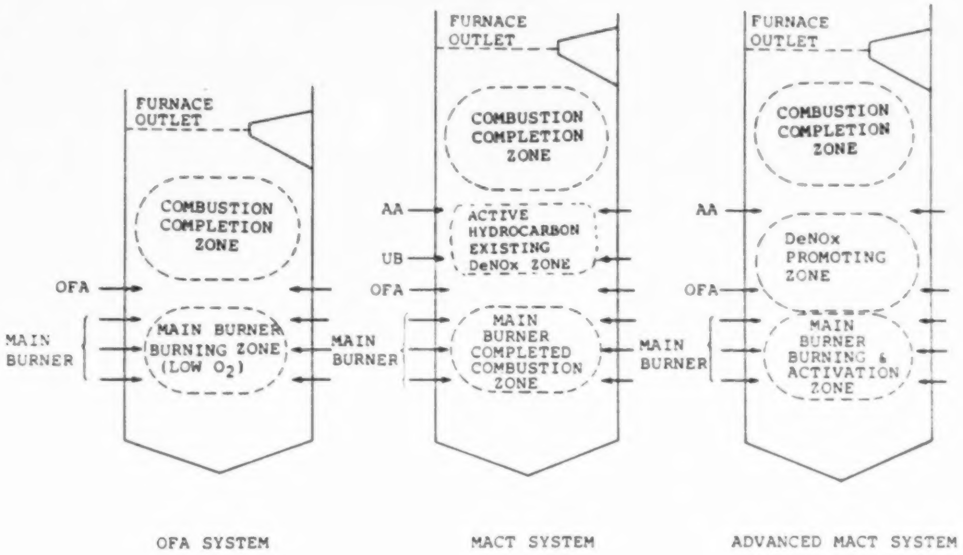

FURNACE OUTLET
COMBUSTION COMPLETION ZONE
OFA
MAIN BURNER
MAIN BURNER BURNING ZONE (LOW O2)
OFA SYSTEM
FURNACE OUTLET
COMBUSTION COMPLETION ZONE
AA
UB
ACTIVE HYDROCARBON EXISTING DeNOx ZONE
OFA
MAIN BURNER
MAIN BURNER COMPLETED COMBUSTION ZONE
MACT SYSTEM
FURNACE OUTLET
COMBUSTION COMPLETION ZONE
AA
DeNOx PROMOTING ZONE
OFA
MAIN BURNER
MAIN BURNER BURNING & ACTIVATION ZONE
ADVANCED MACT SYSTEM

Figure 3. Principle of MACT

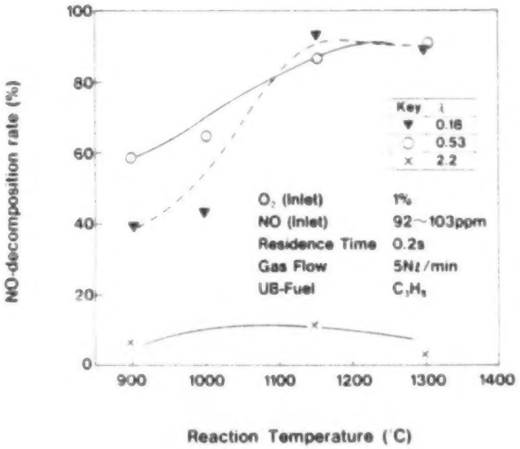


Figure 4. NO-decomposition rate versus Reaction Temperature

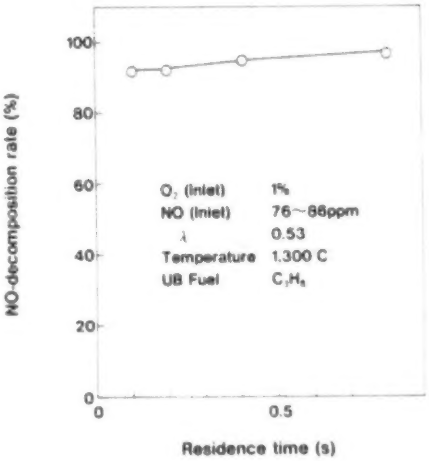


Figure 5. NO-decomposition rate versus Residence Time

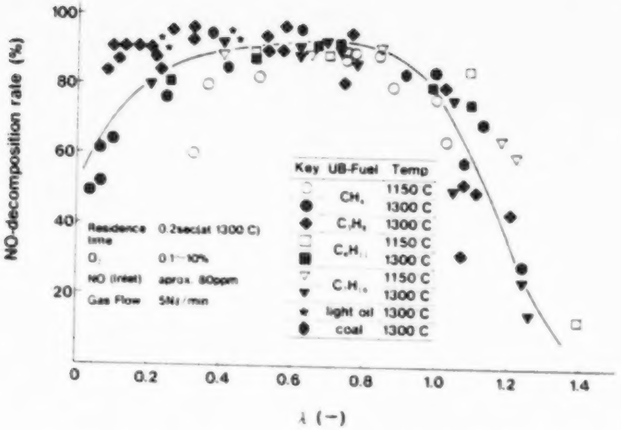


Figure 6. NO-decomposition rate versus Air Ratio (λ) of various fuels

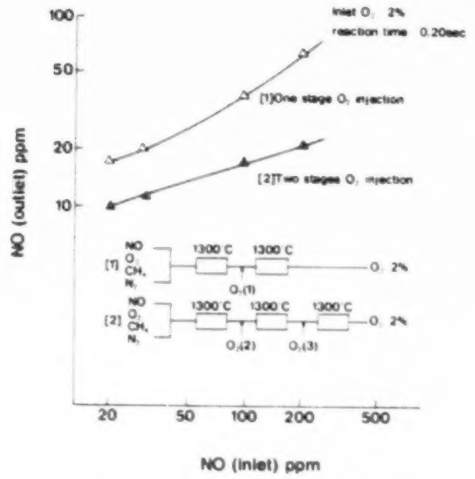


Figure 7. The Effect of two stages O_2 Injection for Complete Combustion Process

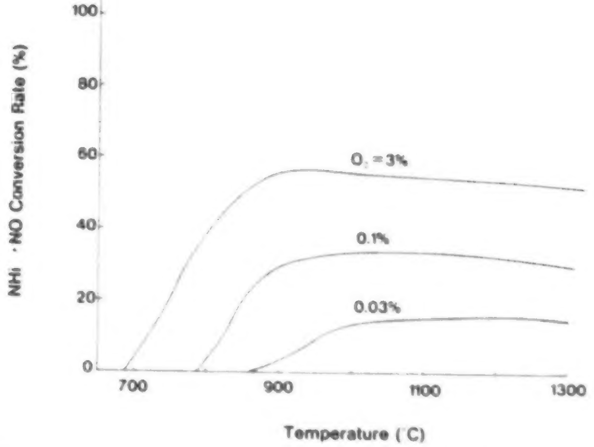


Figure 8. Conversion rate from NHi to NO in AA Process

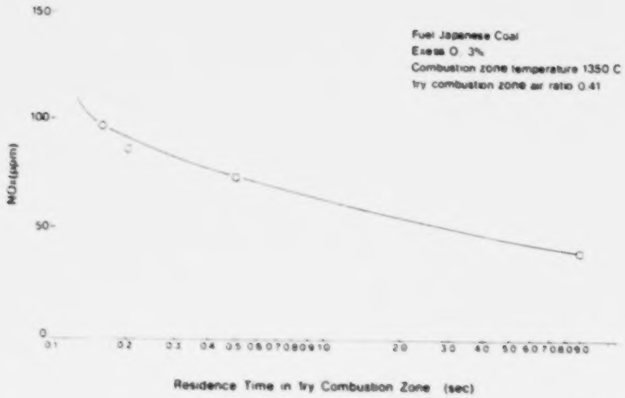


Figure 9. NOx versus Residence Time in 1ry Combustion

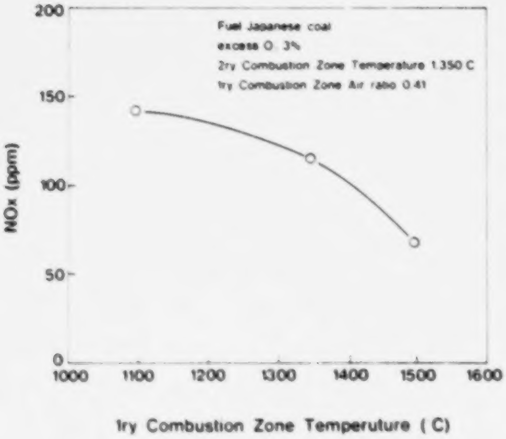


Figure 10. NOx versus 1ry Combustion Zone Temperature

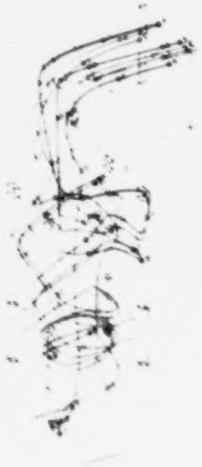


Figure 11. Flow Analysis in Furnace using FEM

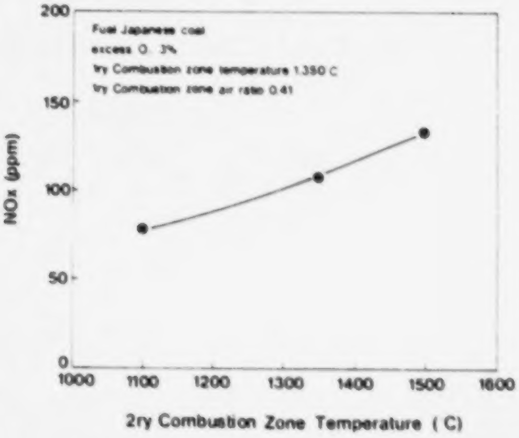


Figure 12. NOx versus 2ry Combustion Zone Temperature

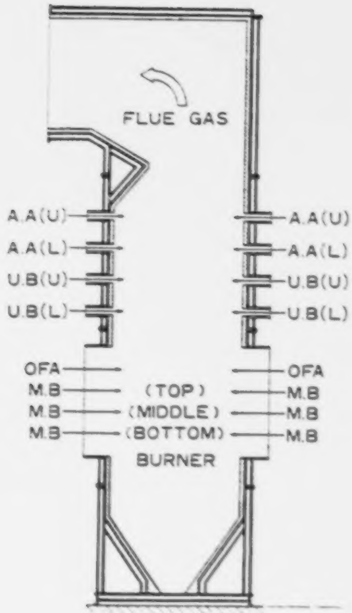

FLUE GAS
A.A(U)
A.A(L)
U.B(U)
U.B(L)
OFA
M.B
M.B
M.B
(TOP)
(MIDDLE)
(BOTTOM)
BURNER
A.A(U)
A.A(L)
U.B(U)
U.B(L)
OFA
M.B
M.B
M.B

Figure 13. Configuration of 3 t/h Corner Firing Test Furnace

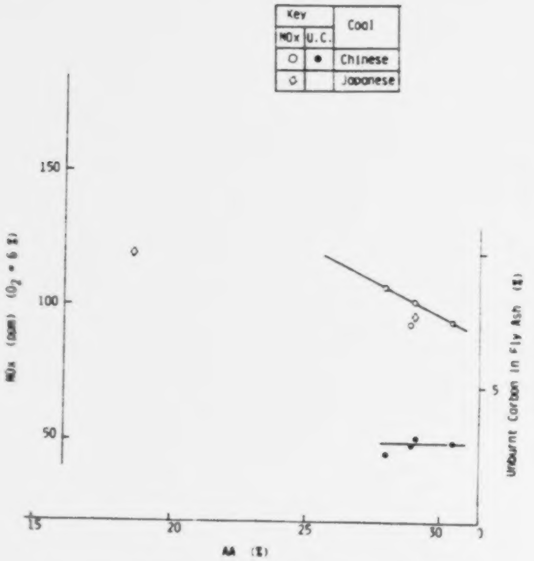


Figure 14. NOx and Unburnt Carbon versus AA

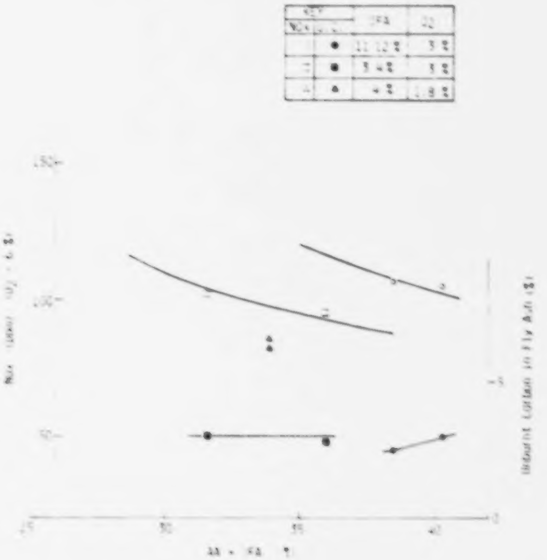


Figure 15. NOx and Unburnt Carbon versus AA and OFA

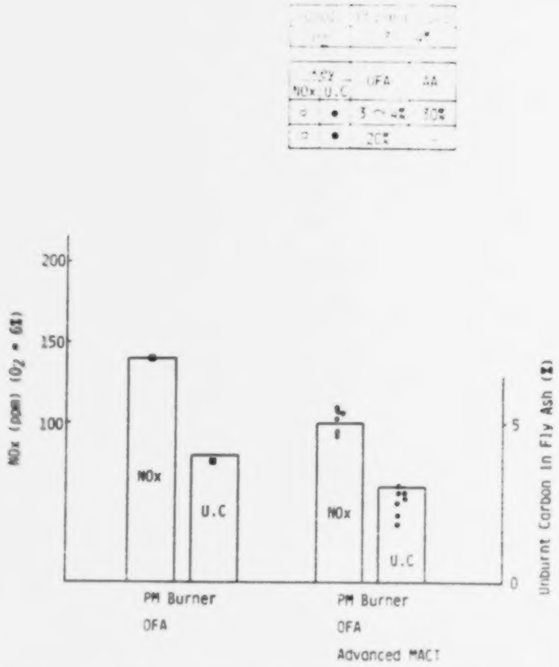


Figure 16. Effect of Advanced MACT at Test Furnace

Reproduced from best available copy.

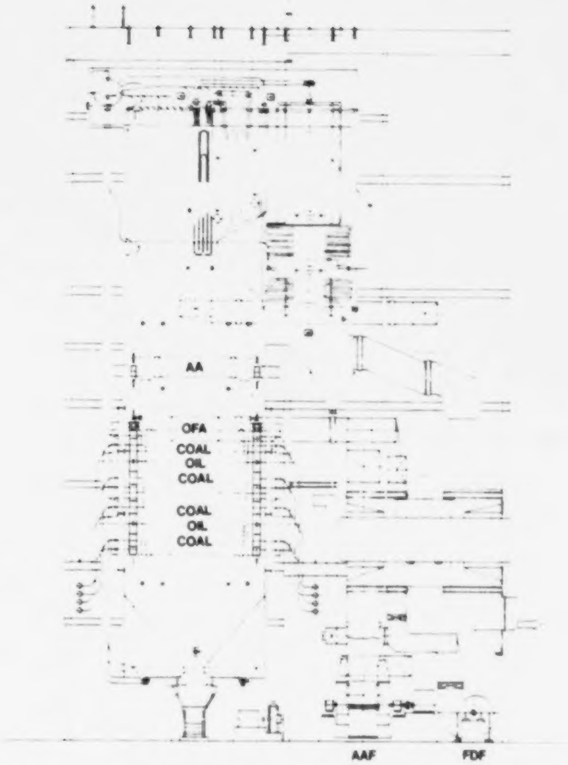

AA
OFA
COAL
OIL
COAL
COAL
OIL
COAL
AAF
FDF

Figure 17. Arrangement of Taio Mishima No. 18, 350 t/h Industrial Boiler (Side View)

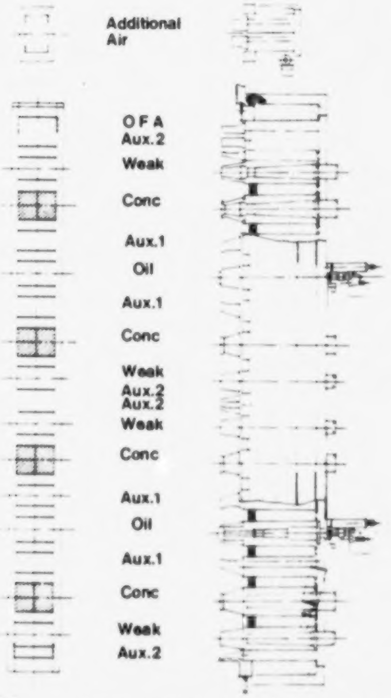

Additional Air
O F A
Aux.2
Weak
Conc
Aux.1
Oil
Aux.1
Conc
Weak
Aux.2
Aux.2
Weak
Conc
Aux.1
Oil
Aux.1
Conc
Weak
Aux.2

Figure 18. Arrangement of Burner Windbox

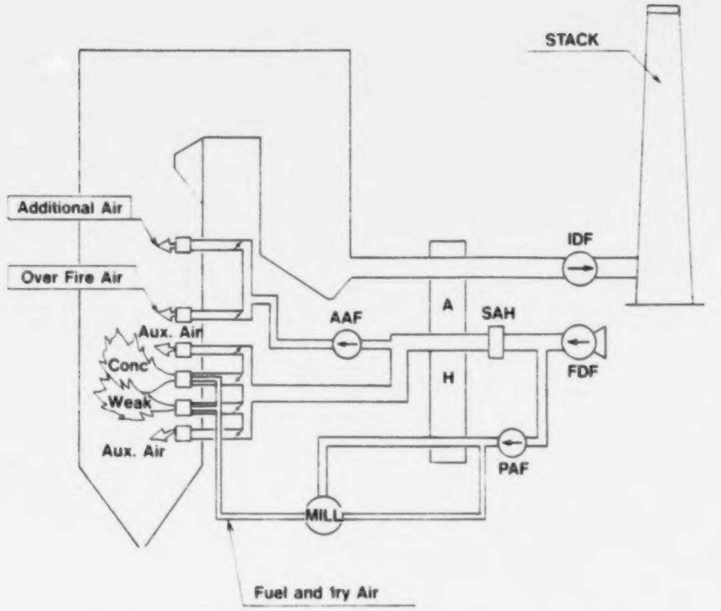

STACK
Additional Air
Over Fire Air
Aux. Air
Conc
Weak
Aux. Air
IDF
AAF
A
H
SAH
FDF
PAF
MILL
Fuel and 1ry Air

Figure 19. Air and Gas Flow Diagram

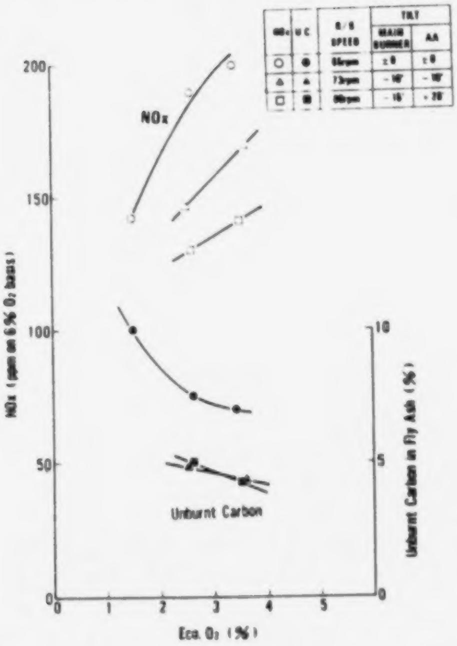


Figure 20. NOx and Unburnt Carbon versus O_2

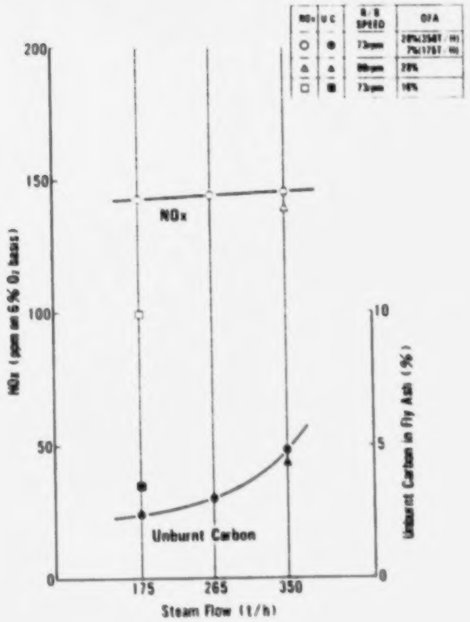


Figure 21. NOx and Unburnt Carbon versus Load

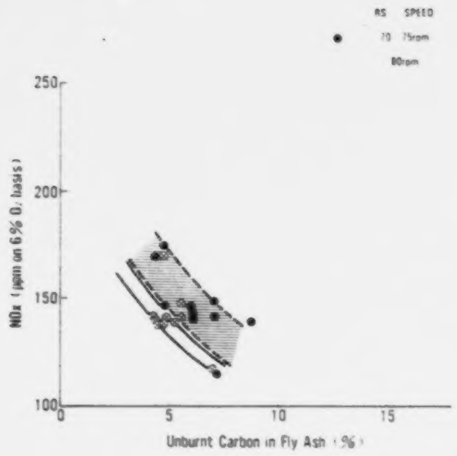


Figure 22. NOx versus Unburnt Carbon in Fly Ash

Table 1. Coal used at Test Furnace

Item \ Coal Kind			Chinese Coal	Japanese Coal
Heating Value (HHV-S.M Free)		kcal/kg	7.040	6.190
Proximate Analysis	Inherent Moisture	%	5.1	5.4
	Fixed Carbon	%	57.9	35.8
	Volatile Matter	%	29.2	43.3
	Ash	%	7.8	15.5
	Fuel Ratio (FC/VM)	—	1.98	0.83
Ultimate AnAlysis	Carbon	%	77.3	65.7
	Hydrogen	%	4.6	5.2
	Oxygen	%	8.4	11.9
	Nitrogen	%	0.80	1.0
	Total Sulphur	%	0.67	0.3

Table 2. Design Condition

Boiler type	Mitsubishi-CE Natural Circulation Boiler Radiant Type
Main Steam Flow (at MCR)	350,000kg/h
Steam Pressure (at MCR)	134kg/cm^2-g
Steam Temperature (SH Outlet)	542°C
Feed Water Temperature (ECO Inlet)	195°C
Fuel	Coal, Residual oil
Draft System	Balanced Draft System
Primary Air System	Cold Primary Air System
Firing System	Tangential Corner Firing System
Pulverizer	Mitsubishi-CE Bowl Mill (703 RP)4 sets (with rotary separator)
Coal burner	16 sets
Oil burner	8 sets

Table 3. Fuel Analysis

Fuel Analysis Item		Coal Kind	Design Condition	Combustion Test Newlands
Heating Value (HHV-S.M Free)		kcal/kg	6160～7075	6865
Proximate Analysis	Inherent Moisture	%	1.6～3.5	2.7
	Fixed Carbon	%	35.2～59	56.2
	Volatile Matter	%	25.8 ～36.7	27.3
	Ash	%	10～26.3	13.8
	Fuel Ratio (FC/VM)	–	0.96～2.23	2.06
Ultimate Analysis	Carbon	%	82.1～84.4	84.26
	Hydrogen	%	4.9～5.9	5.23
	Oxygen	%	7.4～10.5	8.25
	Nitrogen	%	1.1～1.9	1.67
	Total Sulphur	%	0.4～3.1	0.59
Grindability		HGI	43～55	55

Table 4. Supply List of MACT

Plant Name	Burner Type	Fuel(MB)	Fuel(UB)	Gen Output	Comm Operation	Note
Tokyo EPC Chiba #2	PM	Oil	Oil	125MW	FEB. 1981	retrofit
Joban Joint EPC Nakoso #8	SGR	Oil/Coal	Oil	600MW	SEP. 1983	
Sakata Joint EPC Sakata #1	PM	Coal	—	350MW	SEP. 1984	Future
Sakata Joint EPC Sakata #2	PM	Coal	—	350MW	1990	Future
Hokuriku EPC Tsuruga #1	PM	Coal	—	500MW	JULY 1990	
A-EPC A #1	PM	Coal	—	700MW	OCT. 1991	
Mitsubishi Yuka Yokkaichi #1	Conventional	Oil	Oil	280T/H	JUNE 1982	
Mitsubishi Acetate Toyama	PM	P.Coke	—	75T/H	SEP. 1985	Future coal
Kanebo Hofu	PM	Coal	Oil	130T/H	SEP. 1985	
Teijin Tokuyama	PM	Coal	—	80T/H	APR. 1986	
Taio Paper Mishima #18	PM	Coal	—	350T/H	MAY 1986	
Ehime Paper Mishima	PM	Coal	—	95T/H	JUNE 1986	
5 other industrial boilers	PM	Coal	—			

OPERATING EXPERIENCES OF COAL FIRED UTILITY BOILERS USING HITACHI NOx REDUCTION BURNERS

by : Tsuneo Narita
Executive Managing Director
Babcock-Hitachi K.K. Tokyo, 100, Japan

Fumio Koda
Deputy Manager, Thermal Power Design Dept.

Tadahisa Masai
Senior Engineer, Combustion Systems
Thermal Power Design Dept.

Shigeki Morita
Leader Engineer, Combustion Systems

Thermal Power Design Dept.
Babcock-Hitachi K.K. Kure, Hiroshima, 737, Japan

Shigeru Azuhata
Senior Researcher, Coal Technology Center
Hitachi Research Laboratory, Hitachi Ltd.
Ibaragi, 319-12, Japan

ABSTRACT

Babcock-Hitachi K.K. has replaced Dual Register Burners with Hitachi NOx Reduction burners (HT-NR) on two coal fired 200 MWe boilers. The HT-NR burner was developed, as previously reported, to apply the concept of In-Flame NOx Reduction. The two retrofitted boilers have achieved further NOx reduction, without increased unburned carbon contents or any other operating problems. Actual NOx emissions depend on the volatile matter content of the coal and, with highly volatile coal, emissions range from 70 to 75 ppm (6 % O_2).

Five different coals are being fired in these units. Rapid ignition and flame stabilization are enhanced by use of a new type ceramic stabilizer. Even lower levels of NOx and unburned carbon can be achieved by increasing the coal fineness.

OPERATING EXPERIENCES OF COAL FIRED UTILITY BOILERS USING HITACHI NOx REDUCTION BURNERS

INTRODUCTION

In the last 15 years, Japan's low NOx combustion technologies have achieved remarkable developments due to the country's stringent environmental protection controls. For natural gas firing and oil firing, Japan's combustion technologies now achieve extremely low NOx levels ; however, on account of the recent worldwide change in the industrial fuel situation, the need for coal utilization in Japan is on the increase. Japan's electric power utility companies and boiler manufacturers are now concentrating on pulverized coal firing low NOx combustion technologies. In pulverized coal combustion, the principal formation of NOx originates from chemical bound nitrogen contained in the fuel (Fuel NOx). It has already been confirmed that such thermal NOx abatement countermeasures like flue gas recirculation through burners, etc., which constitute effective procedures relative to gas or oil firing, will not show dramatic effects for coal firing.

Under these circumstances, the practical techniques applied to pulverized coal firing boilers, which have already shown remarkable NOx abatement effects, are as follows :

- Low-NOx burners -- low-NOx burners which, through delayed combustion, decrease temperatures and extend the length of flames.
- Low-NOx furnaces -- Two Stage Combustion (TSC) in which the "after-air" (or "over-fire-air" or "bias-air") is provided down stream of the burner zone.

The In-Furnace NOx Reduction ("IFNR") system has not yet reached the stage where it can be applied to commercial operation on large capacity utility boilers in Japan.

However, in the case of low-NOx burners, which simply lengthen the flame by means of delayed combustion, the combustion rate slows down and it is extremely difficult to control the relationship of trading-off between low-NOx and unburned carbon in fly ash. In order to improve such a situation, expanded boiler furnace combustion completion zones, etc., must be taken into consideration.

In contrast, TSC is a technique in which after-air is separated from the burner zone and fed to the post burner zone. Accordingly, it will be possible to accelerate post flame NOx decay and augment NOx reduction by TSC through the increased Residence time of combustion gas between the burner zone and the after-air injection zone. Essentially it means that an enlarged furnace volume between the burners and the after-air ports will be required.

In other words, maintaining unburned carbon in fly ash to low values and yet achieving extremely low-NOx combustion through application of the above technique may be possible for newly installed boilers for which boiler furnace design can be comparatively flexible. However, application without furnace volume changes, in existing boilers, involves a considerable degree of hesitation and risk.

For such reasons, techniques extending conventional furnaces may have been applied to newly installed boilers, but there have been almost no examples of such conversions applied to existing boilers (even those equipped with conventional low NOx burners and TSC's).

Babcock-Hitachi K.K.'s engineers noted the phenomenon of overshooting combustion intermediates in a fuel rich flame which decompose nitrogen oxide efficiently over a period measured in tens of milliseconds, and attempted to apply this phenomenon to the flame structure of a pulverized coal firing burner.

Now the Hitachi-NR burner has been put into commercial production for the first time by Babcock-Hitachi K.K. This is an "In-Flame NOx Reduction" type burner. The use of this burner permits drastic lowering of NOx levels with no adverse effects of decreased flame temperatures or unnecessarily lengthened flames. Accordingly, the difficult relationship between "NOx reduction" and "Increased unburned carbon" has been improved.

Verification of the principle using Babcock-Hitachi K.K.'s 4.0 x 10^6 kcal/h furnace (single burner) and 10.0 x 10^6 kcal/h furnace (18 burners) as well as an example of conversion of an industrial boiler (80 t/h evaporation) have already been presented at the previous session of the Symposium (in Boston, Mass., 1985). Recently, Babcock-Hitachi K.K. has applied the Hitachi-NR burner on two 200 MWe low-NOx boilers and achieved great success with the NOx and unburned carbon relationship.

NOx REDUCTION TECHNIQUE BY USING FUEL RICH REACTIONS

CONCEPT

The mechanism of formation of fuel NO attributable to organic chemical bound nitrogen in coal is accounted for by the following two reaction processes.

- Volatile NO -- gas-gas phase reactions
- Char NO -- gas-solid phase reactions

For the volatile NO, since its formation reaction rate is very high, there are limitations in the principle of restricting it on conventional delayed combustion type burners. Accordingly, the chemical function of decomposing the fuel NO once formed, during the process of combustion, constitutes the fundamental concept of low NOx combustion relative to high nitrogen content fuel.

In-Furnace NOx Reduction ("IFNR") or the "re-burning" technique belongs to the narrower NOx destruction method established as a special system. Figure 1 shows the concept of a broader NOx reduction system. The NOx reduction effects, A and B, indicated in the figure, are respectively attributable to phenomena shown in the following notes, that are fundamentally different in the form of their chemical reactions.

- In-Flame NOx Reduction -- Short residence time (in flame). Hydrocarbon intermediates (radicals) overshoot phenomenon. (A).
- Post flame NOx decay -- Long residence time (Extended two-stage combustion). Burner stoichiometric ratio. (B).

Furnace construction and burner effects on NOx emission, based on the lines of these concepts, can be expressed simply with the following formula.

$$
\begin{aligned}
NOx,_{NR} = (1 - \enclose{circle}{\eta_{NR}}) \times NOx,\ conv. \times [1 & \quad \text{- - - - - - - - - -}\ 1\\
- \exp(-k_1 \times SR_B + k_2) & \quad \cdots\cdots\ 2\\
- \exp(-k_3 \times (1/RT) + k_4) & \quad \cdots\cdots\ 3\\
+ \exp(-k_5 \times SR_B + k_6) & \quad \cdots\cdots\ 4\\
+ \exp(-k_7 \times RT + k_8) & \quad \cdots\cdots\ 5\\
]\qquad\qquad\qquad &
\end{aligned}
$$

Where,

$NOx,_{NR}$ ------- NOx emission quantity from the boiler furnace through the use of the Hitachi-NR burner (mol/sec)

NOx, conv. ---- NOx emission from the burner zone during the use of the conventional low NOx burner (mol/sec)

η_{NR} ---------- In-Flame NOx Reduction effect through the use of the Hitachi-NR burner (-)

$(1 - \eta_{NR}) \times$ NOx, conv. --- NOx emission from the burner zone during the use of the Hitachi-NR burner (mol/sec)

SR_B ----------- Stoichiometric ratio in the burner zone (-)

RT ------------ Average residence time of combustion gas between the burner zone and the after-air port (sec)

Mark 1 ------ In-Flame NOx Reduction efficiency (-)

Mark 2 , 3 -- Post flame NOx decay (-)

Mark 4 , 5 -- NOx re-formation in the combustion completion zone (-)

The larger the RT, ie, the larger the distance between the top burner and the after-air port, the greater will be the post flame NOx reduction effects. However, the RT is directly related to the furnace height. Hence, effects due to increased RT may be taken into consideration during the design phase of a new project's boilers. However, any attempt at retrofitting and increasing effects in existing boilers with the arrangement of burners and the after-air ports already defined, and involving the restriction of boiler furnace volumetric capacity will not be feasible.

In relation to NOx countermeasures, such restrictions are related to a greater or lesser degree. Accordingly, in many cases when making delivery of a new low NOx burner unit, selection has been made aiming at boilers in new projects where design will be more flexible, or at existing boilers with a sufficient allowance of boiler furnace volumetric capacity.

HITACHI-NR BURNER

In Japan, even though almost all of the existing pulverized coal fired boilers are already equipped with TSC facilities and conventional low NOx burners, a further low NOx move is necessary. However, the incompatibility risk of low-NOx vs. increased unburned carbon in fly ash is involved. In particular, in power stations using imported coal having comparatively low volatile contents, careful studies have been accumulated by power stations and boiler manufacturers.

The Hitachi-NR burner (HT-NR) has been successfully put into commercial production by Babcock-Hitachi K.K. in an attempt to decrease the above mentioned risks. Application is aimed at burners having the advantages of the most up-to-date technology covering, as well, boilers to be newly designed, manufactured and installed in the future.

The concept of the HT-NR comprises, "In-Flame NOx Reduction, I-'F'-NR". The key point comprises, "High Temperature NOx Reduction, HT-NR". Figure 2 shows the concept of In-Flame NOx Reduction in a pulverized coal flame. The volatile NO has an extremely large chemical formation rate and the formation is observed simultaneously with the formation of the flame surface. However, under fuel rich conditions, in line with the rapid progress of O_2 consumption, excessive hydrocarbon intermediates (hydrocarbon radicals, etc.) come into play and contribute to the decomposition of NO ingredients.

The NO decomposition reaction passes through ·NH and other N-compound intermediates, and takes place, according to 3ry air mixing of the "time-differential", in a period comprising tens of milliseconds. Moreover, mixing after the "time-differential" is rapid where the designed mixing mode of air makes reduction conversion until N_2 is augmented for final combustion.

In the Hitachi-NR burner the advantage of swirl burners, which can control flame structures individually, is put to the utmost utilization in achieving accelerated In-Flame NOx Reduction. The following three technical advantages augment the magnitude of the effects dramatically.

(1) Rapid ignition by the flame stabilizing ring with ceramic parts.

(2) Separation of tertiary air by the guide sleeve.

(3) Promotion of reduction by more highly efficient swirl.

The first process above is effective in rendering coal contained organic nitrogen compounds, transformed promptly to gas phase, easier for reaction treatment. Also, the flame is maintained at a high temperature making it possible to prevent unnecessary delayed combustion from occurring.

The second process is effective in shaping the reducing flame. Relative to the high temperature reducing flame during the initial phase of combustion, an auxiliary function will be at work to ensure that excessive contact of tertiary air is avoided. Particularly, when replacing existing burners, it is conceivable that rearrangement of the water wall tubing will not be desirable from a viewpoint of economy. In such a case it sometimes occurs that the burner throat diameter is not suitable for formation of a low NOx flame structure. The guide sleeve will be extremely effective in correcting the initial condition of the ring type jet of the tertiary air.

The third process is indispensable for accelerated mixing occurring at the post flame side. Coupled with the high performance tertiary air swirling, the advantages of the independent swirling flame system can be utilized for low NOx activities to the full extent by using the In-flame NOx Reduction phenomenon. Thus, no air injection ports around the burner throats will be required in the future. (See Figure 3)

REPLACEMENT OF THE DUAL REGISTER BURNERS WITH THE HITACHI-NR BURNERS ON TWO COAL FIRED 200 MWe BOILERS

TECHNICAL SIGNIFICANCE

When new mode burners are applied to newly installed boilers, the other major effects influencing low NOx & unburned carbon - the furnace volume, burner arrangement, mill/burner system performance, etc., - call for full consideration, and, therefore, in many cases, it will be difficult to establish the low NOx & low unburned carbon performance, achievable by the burner itself, independently from the combustion data.

In contrast, when the burner units are to be replaced in existing boilers equipped with TSC facilities and conventional type low NOx burners, the net low NOx & unburned carbon effects can be extracted very simply through the use of data explained earlier in this paper.

MODIFICATION OF THE TWO EXISTING COAL FIRED 200 MWe BOILERS

The two coal fired 200 MWe boilers, which were converted, had been utilizing, since their initial operation, Babcock and Wilcox (U.S.A.) Low-NOx P.C. burners, Dual Register Burners (DRB) and Two-Stage Combustion equipment. They operated smoothly until November 1985 (No. 1 unit) and February 1986 (No. 2 unit) when all the DRBs were replaced with Hitachi-NR burners.

The principal specifications are shown in Table 1. The boiler furnace configuration is shown in Figure 4. Each boiler furnace is of B&W-Carolina type having the same dimensions, capacity and arrangements of 2 rows x 4 burners x opposed, total 16 burners, and 1 row x 4 ports x opposed, total eight after-air ports. No large TSC effects can be expected. Also, as the combustion completion space above the AAPs is confined, this adds to the difficulty of taking unburned carbon countermeasures. These factors were already confirmed before the retrofit project was undertaken.

OBJECTIVE

Table 2 shows the retrofit items and the following points which were focused on after the retrofit ;

- The net efficiency of NOx reduction by using HT-NR burners at the same levels of unburned carbon in fly ash.
- Boiler operation restriction
- Flame stability
- The effect of coal property and coal fineness

COAL PROPERTY

The same kinds of coal, four imported coals and one domestic coal, were used for the commercial operation before and after the retrofit. (See Table 3.)

- Coal A -- South African Coal. N content is the highest of the 5 coals. Bad Grindability depending on its lower HGI.
- Coal B -- South African Coal. Shows medium properties.

- Coal C -- Australian Coal. Volatile Matter content, dry ash free, is the lowest quality of the 5 coals.
  Lowest ash content.

- Coal D -- No unique factors.

- Coal E -- Domestic (Japanese) Coal.
  Higher Volatile Matter content and lower N content.

RESULTS

NOx-UNBURNED CARBON CONTENT PERFORMANCE

The combustion tests focused on Coal A and Coal C firing because these two present the most difficulties with NOx and unburned carbon in the fly ash. Figure 5 shows the combustion test results of Coal A and Coal C firing at 200 MWe turbine output.

In Figure 5 ;

- The scatter in the measured values of "before retrofit" shows the region of data during 1 year's operation.

- The "before retrofit" data was obtained immediately before the replacement of the Dual Register Burners.

- The data was obtained under conditions of almost the same stoichiometric ratio of the burner zone "before retrofit" and "after retrofit".

- The scatter in the measured values of the "after retrofit" data are attributed to the different conditions of the pulverized coal fineness and of the excess air ratio.

For two coals, 35 % ~ 45 % of NOx reduction efficiency by replacing with HT-NR burners was confirmed under the condition of the same unburned carbon content in fly ash.

MINIMUM NOx EMISSION LEVEL

The minimum value of NOx emission concentration was obtained by firing Coal E, which has the highest Volatile Matter content and the lowest Nitrogen content out of the 5 coals.

An extremely clear-cut and stable flame allows reductions in the excess air ratio, which means the oxygen concentration in the flue gas leaving the economizer. As a result, extremely low NOx emissions, 70 ~ 75 ppm corrected to 6 % O_2 leaving the economizer, were obtained, with low unburned carbon content in the fly ash during Coal E firing. (See Figure 6)

PULVERIZED COAL FINENESS EFFECT

Concerning pulverized coal fineness in detail : Figure 7 shows the results which were obtained under three fineness conditions. The loading pressure and classifier opening of the mills had a positive influence on fineness. Figure 7 plots only the data of the same unburned carbon content in fly ash as the data obtained before the retrofit. The fineness, by percentage of weight through a 200 mesh sieve, was a constant 68 ~ 72 % during the operation before retrofit.

The result shows that finer pulverized coal contributes to the remarkable features of the HT-NR burner. With the HT-NR burner, rapid ignition is induced by using finer pulverized coal and oxygen is consumed at a very fast rate under a much lower stoichiometry at the burner center zone. Consequently, a relatively higher combustion temperature is attained and this causes devolatilization and generates hydrocarbon radicals which decompose NOx. In such a process, the HT-NR burner can reduce not only unburned carbon in fly ash but also reduce NOx emissions, with finer pulverized coal, at the same time.

COAL PROPERTY vs. NOx REDUCTION EFFICIENCY

In principle, as presented at the last symposium, (in Boston, Mass., 1985), the NOx reduction effect by the HT-NR burner depends on the inflammable gaseous species vaporized from coal particles.

Figure 8 shows that field data also can explain this phenomenon in the relationship between Volatile Matter content (dry ash free) and NOx reduction efficiency. In Figure 8 there was only the data measured with the same unburned carbon content in fly ash as that before retrofit. The scattering of the data depends, mainly, on the fineness conditions.

As shown in Figure 8, it was confirmed that the retrofit of the existing boiler with HT-NR burners brings about a good NOx reduction effect in practical use for these coals' rank. In particular, modification of the mill's performance with HT-NR burners will promise extremely low-NOx combustion performance for existing boilers.

BOILER PERFORMANCE

Figure 9 shows the results of the steam temperatures after retrofit, firing Coal B. There was no significant difference between "before retrofit" and "after retrofit" values. So, this retrofit produced no undesirable effects on the boiler performance concerning steam temperature.

FLAME STABILITY

The HT-NR burner promoted the flame stabilization and made a clear-cut, more visible flame than that of the Dual Register Burner. It was confirmed that there was no problem at 45 MWe - 200 MWe operation.

SLAGGING, FOULING AND ASH MORPHOLOGY

There is no significant difference in slagging, fouling and ash morphology between "before retrofit" and "after retrofit" values. The problems of ash handling and utilization do not increase.

SOOT BLOWING EFFECT

Spray water flow was gradually increased, without using soot blowers, in 8 to 10 hours and that meant that there was some molten slagging on the furnace surface. This is no different from when the Dual Register Burners are used and is tolerable, that is, deposits were successfully controlled by sootblowing at routine intervals.

Figure 10 shows the combustion performance during the soot blower operation. Good combustion performance was confirmed under soot blowing conditions.

NOx PROFILE

NOx concentration profiles at a cross sectional area leaving the economizer are shown in Figure 11 with O_2 and CO concentration profiles. Good balanced profiles were obtained for each commercial operating condition.

ECONOMICAL EVALUATION

As a result, finer pulverized coal in commercial operation contributes to reducing the excess air (i.e. oxygen concentration in flue gas leaving economizer) while decreasing the unburned carbon in the fly ash.

As mentioned above, significant improvement of NOx reduction performance was achieved by this retrofit with HT-NR burners. As a result of the NOx reduction, as shown in Table 4, NH_3 assumption in SCR equipment (De-NOx System post boiler) was significantly reduced.

CONCLUSION

This paper presents an outline of the operation results gained after the replacement of Dual Register Burners (DRBs) with Hitachi-NR burners (HT-NRs) in two identical 200 MWe boiler units about a year ago.

This retrofit was carried out without any modification of pressure parts and the same boiler performance was maintained.

Significant NOx reduction effects, with no increase in the unburned carbon in fly ash, were obtained.

The units are now successfully operating without encountering any problems such as heavy slagging in the furnace or fouling in the convection pass.

LOW NOx STRATEGY IN THE NEAR FUTURE

As mentioned before, the Hitachi-NR burner promotes NOx decomposition reaction mechanisms in the flame chemically, and makes extremely low-NOx combustion, for coal fired boilers with small furnace volume sizes, possible. This field data shows the possibility of reducing the environmental pollutant substances of established boilers operating with high NOx emission levels by only the basic modification of the burners.

On the other hand, the low NOx countermeasures for new boilers should be adopted in the design stage. In Japan, NOx emission levels have been restricted to less than 50 ppm, based on 6 % oxygen content at the stack exit, by local regulations and it is necessary to use SCR equipment. From the standpoint of economical operation, however, we have to clear less than 100 ~ 150 ppm based on 6 % oxygen content by the using the new combustion technique only. As shown in Figure 12 , it is possible to achieve super low NOx emission levels using the Hitachi-NR burner with an optimization of the injection position of the after air ports for two stage combustion and an enlargement of the combustion zone.

In the near future, low NOx emission levels, less than 100 ppm based on 6 % oxygen content, for coal which has a Volatile Matter content (dry ash free) of less than 30 % will be required. Babcock-Hitachi K.K. has started to establish new combustion techniques which include the Hitachi NOx reduction concept and In-Furnace NOx Reduction system.

The work described in this paper was not funded by the U.S. Environmental Protection Agency and therefore the contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

ACKNOWLEDGEMENT

The authors would like to thank their customer both for support given and for the chance to install new technological innovations in commercial utility boilers.

This presentation is introduced through the kind offices of Mr. A.D. LaRue, Babcock & Wilcox, and Mr. D. Eskinazi, Electric Power Research Institute.

REFERENCES

1. Narita, T. and Morita, S. Development of the low-NOx burner for the pulverized-coal-fired In-Furnace NOx reduction system. Paper presented at 1985 Joint Symposium on Stationary Combustion NOx Control, Boston Massachusetts, May 6-9, 1985.

2. Glass, J.W. and Wendt, J.O.L. Mechanisms governing the destruction of nitrogeneous species during the fuel rich combustion of pulverized coal. 19th Symposium (International) on Combustion, pp. 1243-1251, 1982.

3. Muzio, L.J. and Arand, J.K. Gas phase decomposition of nitric oxide in combustion products. 16th Symposium (International) on Combustion, PP. 199-208, 1976.

4. Wendt, J.O.L., Pershing, D.W., Lee, J.W., and Glass, J.W. Pulverized combustion : NOx formation mechanisms under fuel rich and staged combustion conditions. 17th Symposium (International) on Combustion, pp. 77-87, 1979.

5. Masai, T., Morita, S., Akiyama, I., and Otsuka, K. Low-NOx combustion technology for pulverized coal fuel. The Hitachi Review2 vol. 34, No. 5, P. 207-212 1985.

6. Azuhata, S., Narato, K., Kobayashi, H., Arashi, N., Morita, S., and Masai, T. A study of gas composition profiles for low NOx pulverized coal combustion and burner scale-up. Paper submitted to the 21th Symposium (International) on Combustion, 1986.

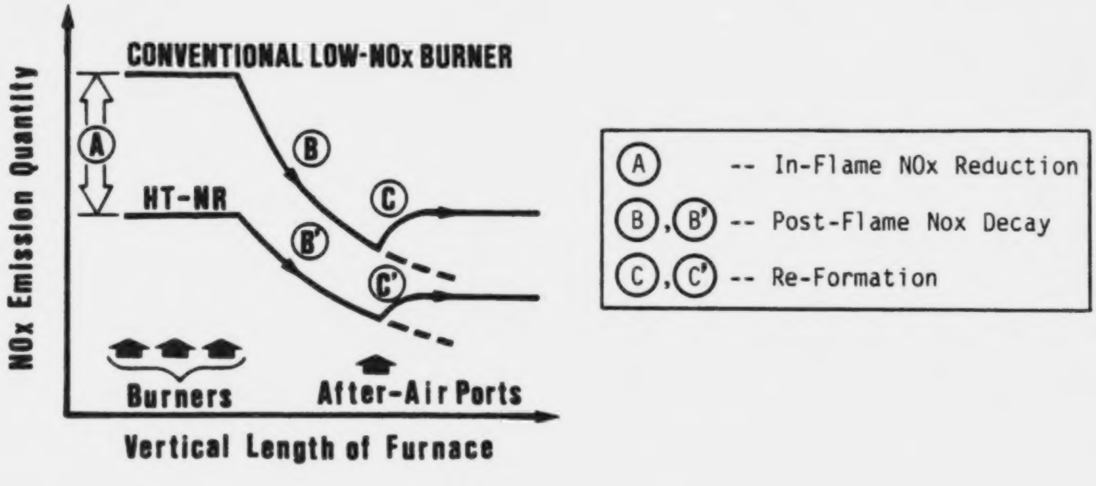


Figure 1. Low-NOx combustion with low-NOx burner and TSC.

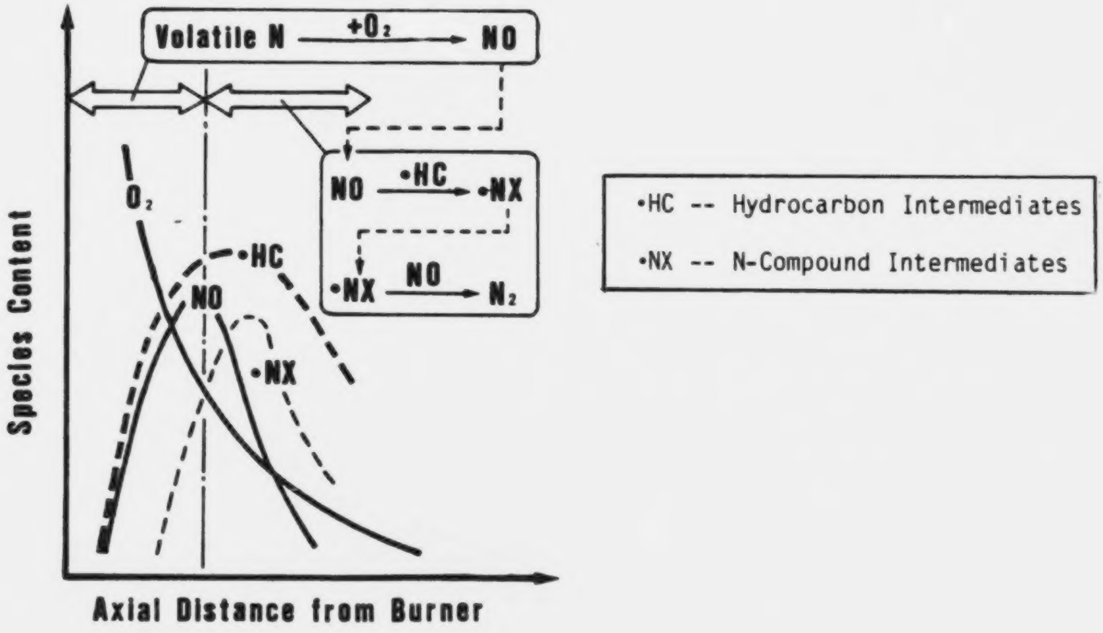

Volatile N $\xrightarrow{+O_2}$ NO
NO $\xrightarrow{\cdot HC}$ •NX
•NX $\xrightarrow{NO}$ N_2
O_2
•HC
NO
•NX
Species Content
Axial Distance from Burner
•HC -- Hydrocarbon Intermediates
•NX -- N-Compound Intermediates

Figure 2. The concept of "In-Flame" NOx reduction.

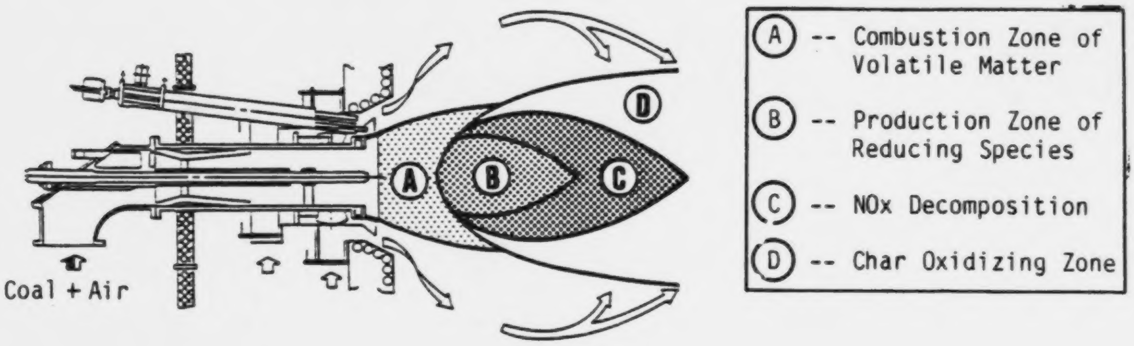

A -- Combustion Zone of Volatile Matter
B -- Production Zone of Reducing Species
C -- NOx Decomposition
D -- Char Oxidizing Zone
Coal + Air
A
B
C
D

Figure 3. Hitachi-NR burner

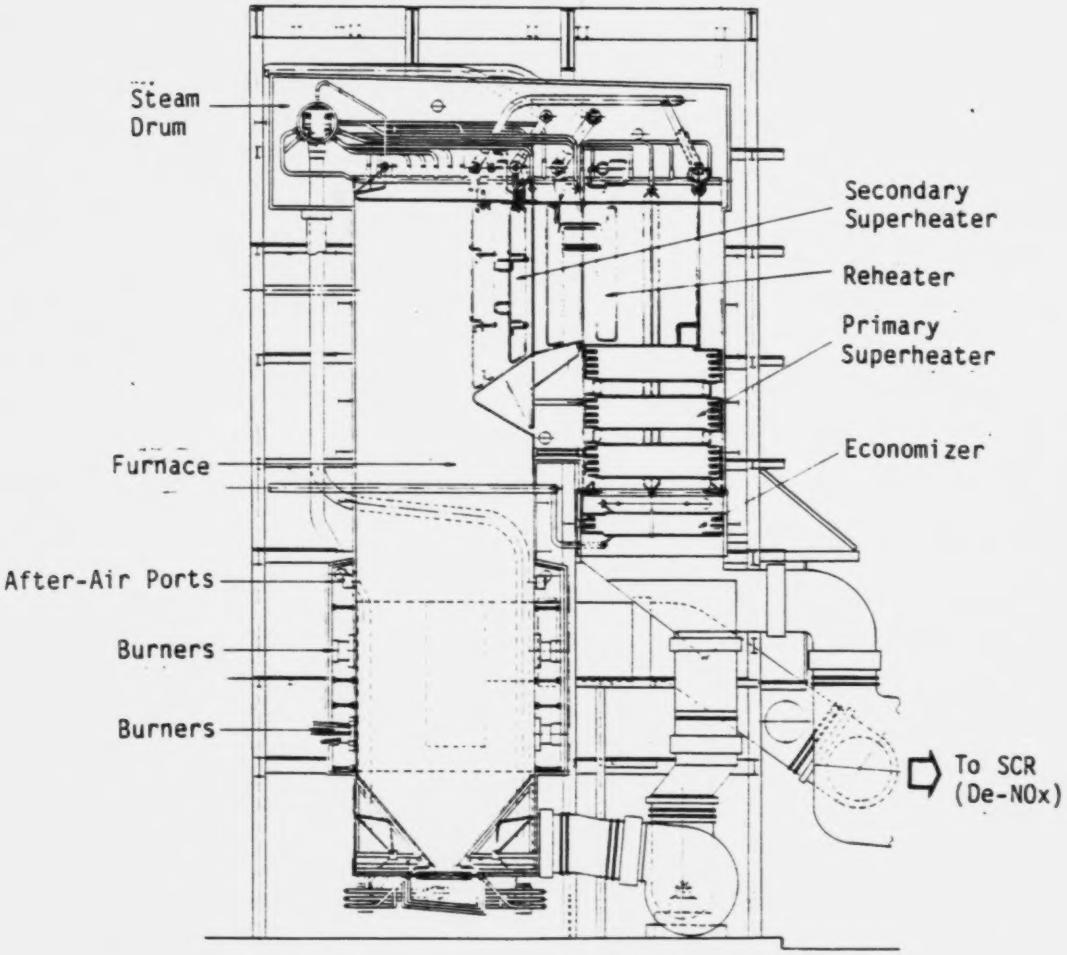
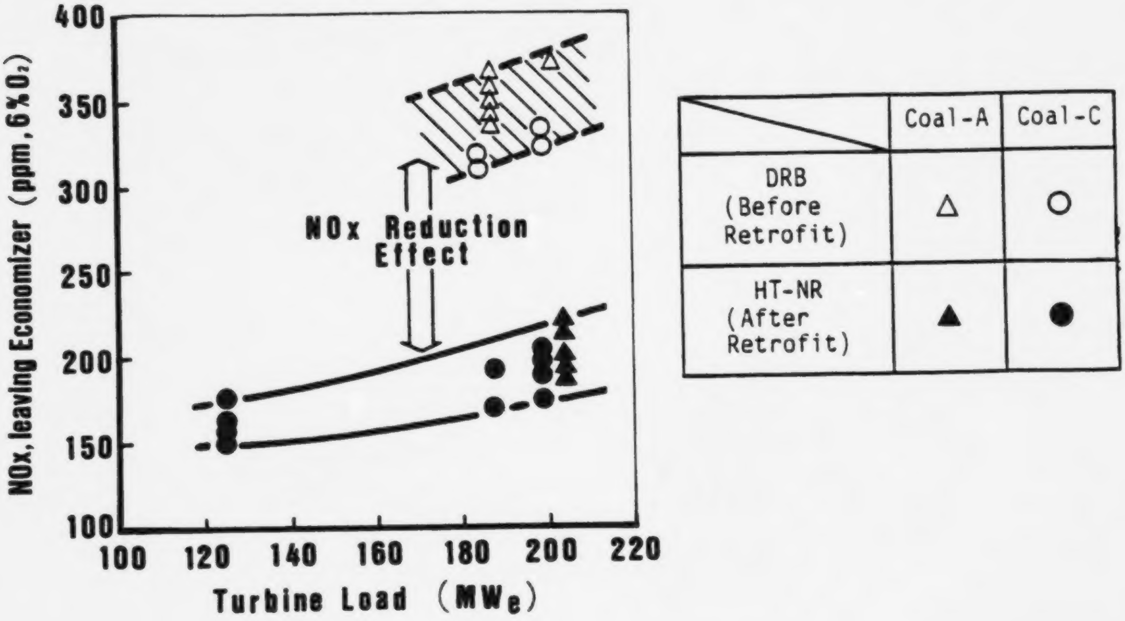
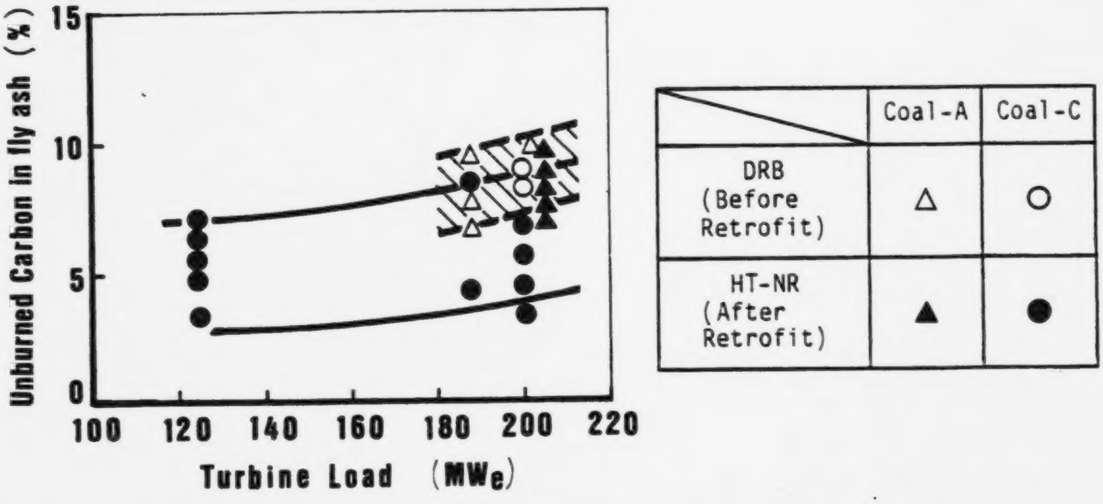

Steam Drum
Secondary Superheater
Reheater
Primary Superheater
Economizer
Furnace
After-Air Ports
Burners
Burners
To SCR (De-NOx)

Figure 4. 200 MWe boiler unit

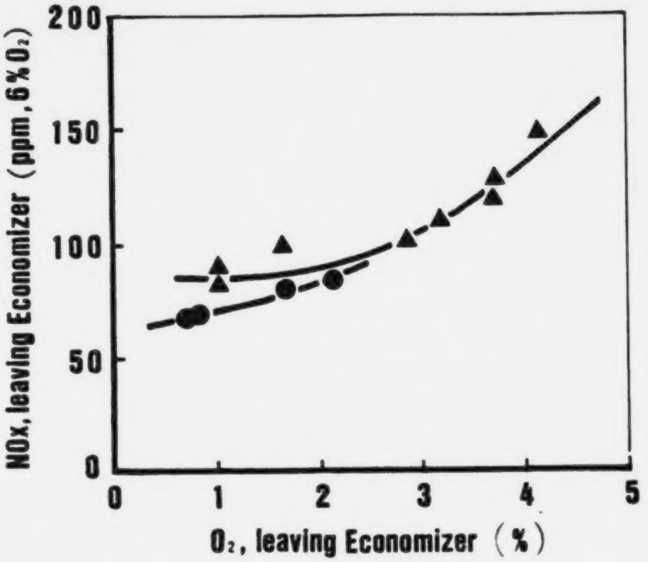


a) NOx emission performance



b) Unburned carbon performance

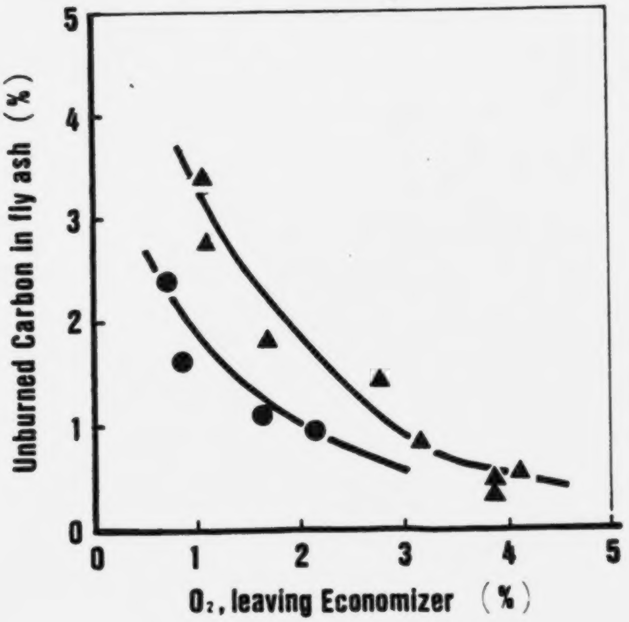
Figure 5. A Comparison between the performance of HT-NR burners and DRBs, Coal A and C.



All data was obtained after retrofit.

	200 Mesh through
–▲–	60 ~ 64 %
–●–	64 ~ 70 %

a) NOx emission performance

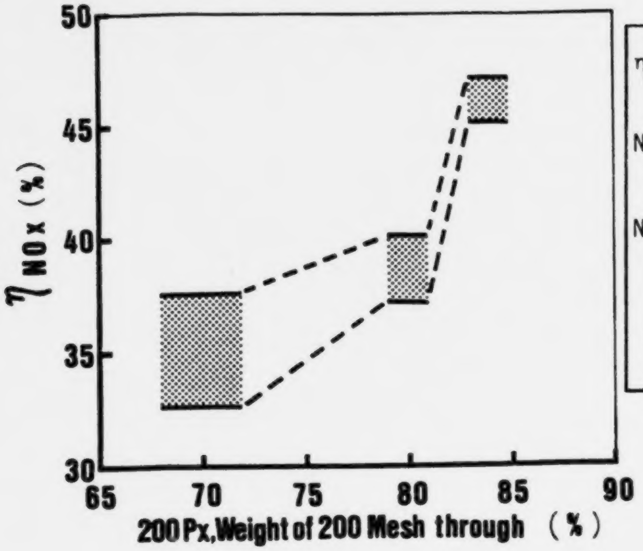


All data was obtained after retrofit.

	200 Mesh through
–▲–	60 ~ 64 %
–●–	64 ~ 70 %

b) Unburned carbon performance

Figure 6. Minimum NOx emission, Coal E.



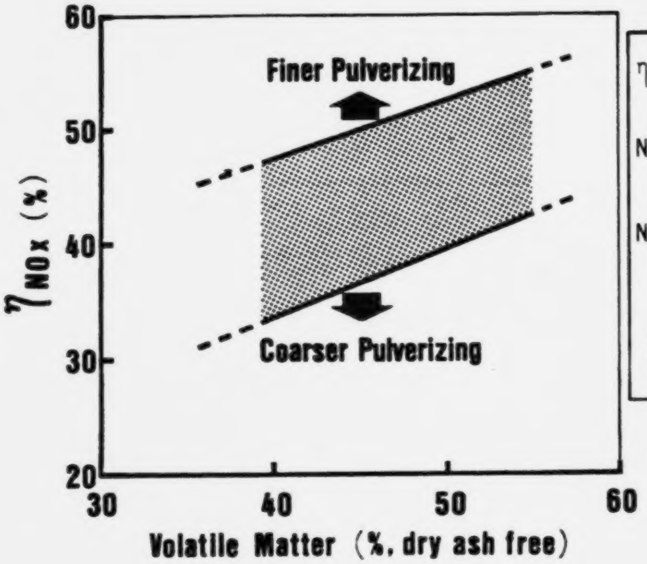
$$\eta_{NOx} = \frac{NOx(1) - NOx(2)}{NOx(1)} \times 100$$

NOx(1) -- NOx Emission Before Retrofit (200 P 68 ~ 72)

NOx(2) -- NOx Emission After Retrofit

NOx(1), (2) : leaving Economizer (ppm, 6 % O_2)

Figure 7. Fineness effect on NOx reduction efficiency, Coal C.



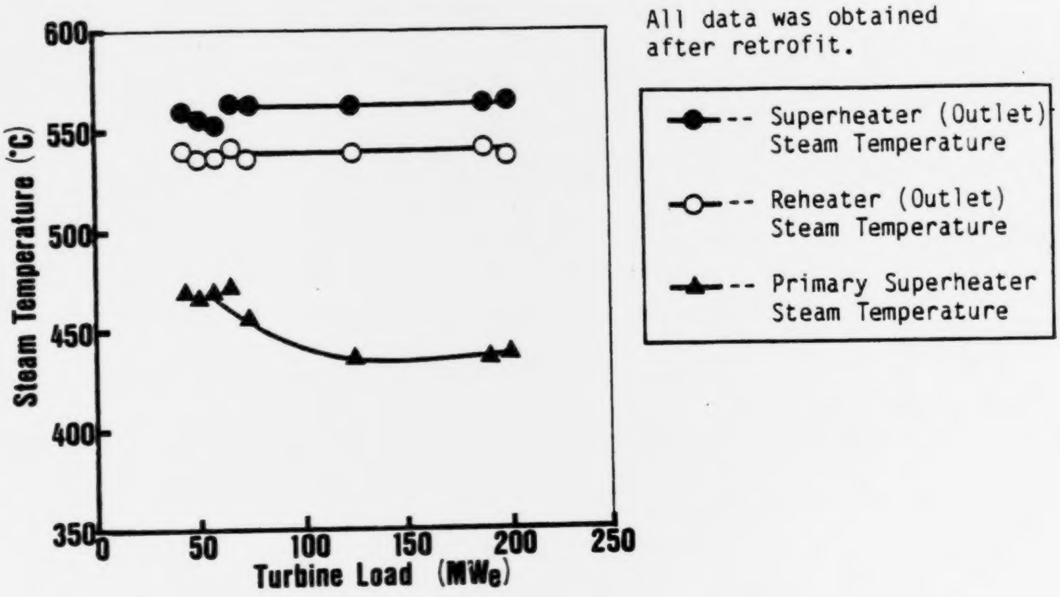
$$\eta_{NOx} = \frac{NOx(1) - NOx(2)}{NOx(1)} \times 100$$

NOx(1) -- NOx Emission Before Retrofit (200 P 68 ~ 72)

NOx(2) -- NOx Emission After Retrofit

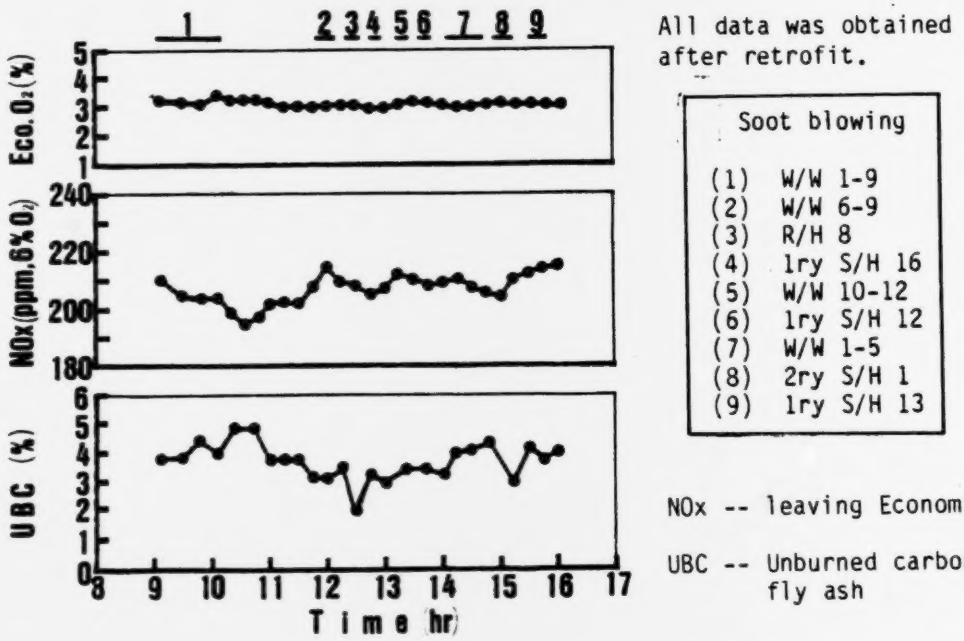
NOx(1), (2) : leaving Economizer (ppm, 6 % O_2)

Figure 8. Volatile matter effect on NOx reduction efficiency, Coal A, B, C, D and E.



All data was obtained after retrofit.

Figure 9. Boiler performance, Coal B.

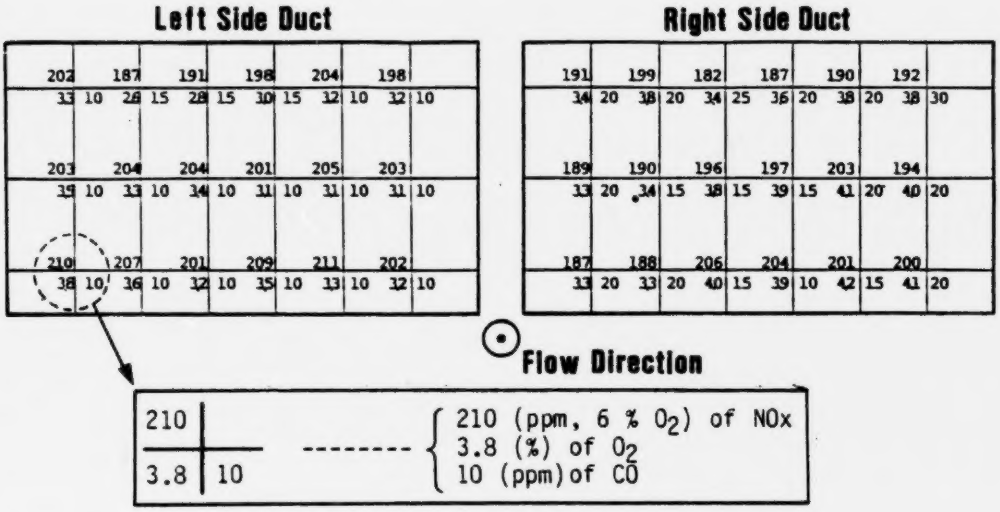


All data was obtained after retrofit.

NOx -- leaving Economizer

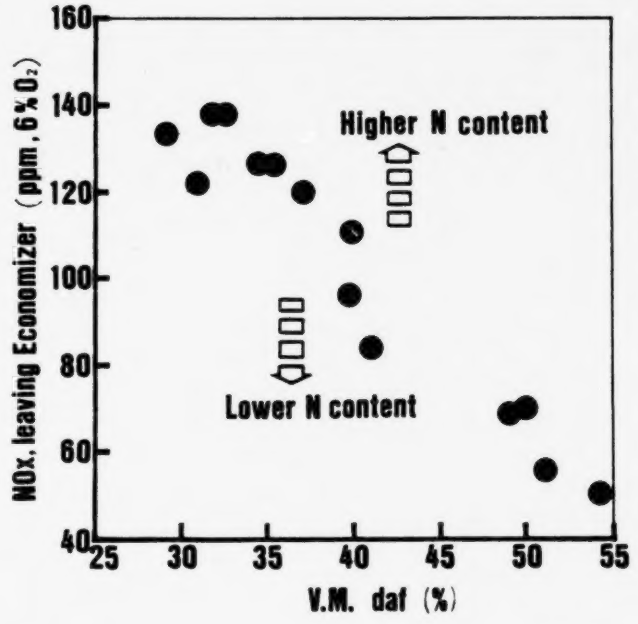
UBC -- Unburned carbon in fly ash

Figure 10. Soot blowing vs. NOx, UBC performance, Coal B.


Left Side Duct
202
187
191
198
204
198
3.3 10
2.6 15
2.8 15
3.0 15
3.2 10
3.2 10
203
204
204
201
205
203
3.5 10
3.3 10
3.4 10
3.1 10
3.1 10
3.1 10
210
207
201
209
211
202
3.8 10
3.6 10
3.2 10
3.5 10
3.3 10
3.2 10
Right Side Duct
191
199
182
187
190
192
3.4 20
3.8 20
3.4 25
3.6 20
3.8 20
3.8 30
189
190
196
197
203
194
3.3 20
3.4 15
3.8 15
3.9 15
4.1 20
4.0 20
187
188
206
204
201
200
3.3 20
3.3 20
4.0 15
3.9 10
4.2 15
4.1 20
Flow Direction
210
3.8
10
210 (ppm, 6 % O2) of NOx
3.8 (%) of O2
10 (ppm) of CO

Unburned Carbon (avg.) = 3 ~ 4 %

Figure 11. NOx, O_2 and CO profiles in the flue gas ducts leaving the Economizer, Coal D.



Case Studies ;
With expanded TSC
& with HT-NR burners

Figure 12. An example of NOx estimation for a new boiler unit.

TABLE 1. BOILER PERFORMANCE

Item	Unit	Planning coal 200 MWe
SH outlet steam flow	kg/h	597,000
RH outlet steam flow	kg/h	491,388
Steam pressure	kg/cm^2g	
Drum		177.9
SH outlet		172.9
RH inlet		28.2
RH outlet		26.7
Steam temperature	°C	
SH outlet		571
RH inlet		330.6
RH outlet		541
Feed water		
Press. (Eco. inlet)	kg/cm^2g	179.8
Temp. (Eco. inlet)	°C	263.4
Boiler efficiency (G.C.V base)	%	88.10
Fuel consumption	kg/h	69,150
G.C.V	kcal/kg	6,510
N.C.V	kcal/kg	6,225
Ambient Air Temp.	°C	20
F'ce heat release (vol.)	$kcal/m^3h$	137,100
Spray water flow	kg/h	
Superheater		55,600
Reheater		0
Feed water flow	kg/h	546,643

TABLE 2. RETROFIT ITEMS

		"before"	"after"
Output		200 MWe (Tb)	The same
Combustion method		Two stage combustion	The same method
Burners	Type	Conventional low NOx burner "Dual register burner based on B&W Co. design"	New extremely low NOx burner "Hitachi-NR burner"
	Arrangement	2 rows x 4 burners x opposed = 16 burners	The same arrangement and position (no modification)
After air ports	Type	Conventional type	Small modified (for future over-load operation)
	Arrangement	1 row x 4 ports x opposed = 8 ports	The same arrangement and position (no modification)

TABLE 3. ANALYSIS DATA OF COALS USED FOR COMMERCIAL OPERATION

		Base	Unit	South Africa		Australia		Japan
				Coal A	Coal B	Coal C	Coal D	Coal E
HHV		A.D	cal/g	6920	6780	7410	7080	6540
Proximate	Moisture	W.B	%	4.01	3.95	3.78	3.09	5.97
	I M	A.D	%	2.77	2.36	2.14	1.84	4.32
	V M	D.B	%	33.68	30.52	31.24	33.32	45.72
	F C	D.B	%	55.64	53.98	60.54	54.28	40.88
	Ash	D.B	%	10.68	15.50	8.22	12.40	13.40
FR (= FC/VM)		-	-	1.65	1.77	1.94	1.63	0.89
Density		-	g/cm^3	1.386	1.399	1.344	1.347	1.315
H.G.I		-	-	41 ~ 43	50	53 ~ 55	55	39
Ultimate	C	D.B	%	72.52	70.59	76.97	72.18	66.98
	H	D.B	%	4.53	4.27	4.95	4.77	5.53
	O	D.B	%	10.10	7.20	7.90	8.61	13.02
	N	D.B	%	1.71	1.69	1.52	1.57	0.96
	S (Total)	D.B	%	0.56	0.98	0.46	0.49	0.30
	S (Comb.)	D.B	%	0.46	0.75	0.44	0.47	0.11
	S (Uncomb.)	D.B	%	0.10	0.23	0.02	0.02	0.19
	Cl	D.B	%	0.008	--	0.0047	--	--
	F	D.B	%	0.019	--	0.005	--	--

TABLE 4. ECONOMICAL EVALUATION

	Before retrofit	After retrofit
Eco. outlet O_2 (%)	3.5 ~ 4.0	2.0 ~ 3.0
NH_3 injection (De-NOx) (kg/h)	90 ~ 130	15 ~ 30

LONG-TERM VERSUS SHORT-TERM

DATA ANALYSIS METHODOLOGIES

Impact on the Prediction of NO_x Emission Compliance

Lowell L. Smith
Energy Technology Consultants
Irvine, CA 29715

Wallace S. Pitts, III
Kilkelly Environmental Associates
Raleigh, NC 27622

Randall Rush
Southern Company Services
Birmingham, AL 35202

Timothy Flora
Ohio Edison Company
Lorain, OH 44052

ABSTRACT

Over the last two decades, considerable NOx data from utility and industrial boilers has been accumulated. The data sources range from short-term test results to data obtained from continuous emission monitors from Subpart Da utility boilers. Depending upon the ultimate use of these two types of data, different interpretations of the emission results can be obtained. This can have far reaching impacts if the interpretation of the data is used to establish the long-term effectiveness of NOx control technologies or to establish new or revised emission standards.

This paper provides a discussion of the potential ultimate uses of both short-term and long-term data. The value of both is discussed in terms of their use for establishing emission control trends, operating and retrofit guidelines and emission standard setting. Statistical analysis methodologies are presented for interpreting long-term data and illustrations of Time Series Analysis are presented for interpretation of this data.

I. INTRODUCTION

Over the last two decades, environmental requirements for utility and industrial boiler operators have changed considerably. Until the mid-1970's, supporting data for environmental regulations were generally of a short-term nature and developed from programs that were undertaken to obtain parametric emission characterizations. With the promulgation in 1975 of emission monitoring and reporting requirements for SOx and NOx (Ref. 1) and in 1979 of the revised NOx and SO_2 Subpart Da NSPS for Utility Boilers (Ref. 2) which required continuous emission monitoring for compliance determination, more continuous emission data are available to examine not only the achievability of the promulgated standards but also the potential for new revised standards. More recently, the 1986 Subpart Db NSPS for Industrial Boilers (Ref. 3) was also promulgated requiring compliance by means of continuous data collection. With this in mind, future data collection programs to evaluate control technology capabilities should address those capabilities from a continuous emission compliance standpoint. This is particularly important since the data may also be used to establish new emissions standards. In addition, proper application of these data analysis criteria are useful for gaining a complete understanding of the data.

The intended use of data will, of course, dictate the amount and types of data required. Data taken for performance or engineering purposes are generally of a short-term nature and may not require sophisticated statistical analyses. On the other hand, data taken for regulatory purposes or used to evaluate the consequences of long-term operation or to support emission standards requiring continuous compliance over longer averaging times necessitates data analyses of a much greater sophistication. During the standard setting process for the development of New Source Performance Standards (NSPS) under Subpart Da, the interplay of long-term or average emission data, the numerical value of the emission standard and the averaging time became apparent. The focus of this paper is on the proper analytic techniques for characterizing these long-term data in a regulatory environment.

The U.S. Environmental Protection Agency has generally recognized that short-term data has little relevance to the ability of boilers to comply with long-term continuous standards. EPA has properly recognized that time-series analysis of long-term data is required to establish achievable standards, and is applying this approach for both SO_2 and NOx standards. The illustrations that follow provide insight into the appropriate analysis method for satisfying research program goals and establishing new or revised emission standards. While emphasis is on NOx data analysis for coal-fired boilers, the illustrations also generally apply to the interpretation of other emissions species and other fuels.

II. LONG-TERM DATA ANALYSES AND INTERPRETATION

The following sections provide background discussions of the influence of statistical parameters, test program duration and operational characteristics on the evaluation of NOx emission test data. Several examples are used to illustrate the impact of sample size as well as load and NOx characteristics on the achievable NOx emissions and interpretation of test program data. As will be seen in the following, considerable data and sophisticated statistical analyses are required to adequately characterize long-term NOx emission data. The analysis techniques are, however, manageable but must be handled with care particularly where regulatory issues are important.

A. Important Statistical Parameters

EPA now uses time series statistical analyses of CEM data to support new SO_2 and NOx standards (Ref. 4 and 5). In developing emission standards for both the electric utility NSPS (Subpart Da) and the industrial boiler NSPS (Subpart Db) EPA has relied on statistical analyses to extrapolate from observed process data to an achievable emission standard. The procedure is first to characterize emission data (generally 24-hour averages) in terms of (1) the observed mean emission level and the variation about the mean, (2) the shape of the statistical distribution, and (3) the time variation properties of the data. Once the data are characterized, the achievable emission standard can be estimated. In both the Subpart Da and Db rulemakings, compliance is determined on a 30-day rolling average basis. An average of 1 exceedance of the standard per 10 years was used as an acceptance criteria for developing the standards. This is equivalent to obtaining compliance 99.97 percent of the time.

It should be noted that procedures described hereafter are assumed to have no measurement error in the CEM data and the data are assumed to be completely accurate. Actual CEM data, however, have measurement error. This fact has been noted by EPRI, (Ref. 6) and, more recently, by EPA (Ref. 7) in their evaluations of potential errors introduced by measurement inaccuracies of CEMs. Consequently, while the following analyses assume no inaccuracies, the final analysis of actual CEM data will incorporate these data collection inaccuracies. The incorporation of positive or negative bias will influence the calculated achievable NOx standards shown in the following sections.

1. Variation

The day-to-day variation in emissions about the long-term average is expressed in terms of either the standard deviation, or relative standard deviation (RSD). In certain situations, the mean and standard deviation are independent. That is, the mean level can be increased, while the standard deviation remains constant. Consider the example of data that indicate an average NOx emission rate of 0.80 lb NOx/MMBtu and an RSD of 10 percent (standard deviation of 0.08 lb NOx/MMBtu). Under the assumption of independence between the mean level and standard deviation, if the mean level was decreased to 0.40 lb NOx/MMBtu the standard deviation would remain at 0.08 lb NOx/MMBtu. On the other hand, if the mean and standard deviation are dependent (i.e., constant RSD), then if the mean level decreases (or increases) the variability will decrease (or increase) as well. Under the assumption of constant RSD a reduction from a mean NOx emission rate of 0.80 lb NOx/MMBtu to 0.40 lb NOx/MMBtu would be accompanied by a corresponding reduction in the standard deviation from 0.08 lb NOx/MMBtu to 0.04 lb NOx/MMBtu. EPA used a constant RSD assumption when evaluating compliance scenarios for the NSPS Subpart Db (Ref. 5) and the proposed clarification of NSPS Subpart D (Ref. 8).

2. Distributional Form

Distributional forms indicate how the data vary about the long-term mean. Generally, two distributional forms, the normal, and lognormal, have been found adequate to describe 24-hour average emission rates. There is no guarantee, however, that these two distributions will be adequate for all cases. Other, more complex distributions also exist and their use may be appropriate in some cases. The normal distribution is symmetric, and roughly 68 percent of the observed values can be expected to fall within one standard deviation on either side of the mean. The lognormal distribution, on the other hand, is positively skewed, having a slightly longer tail above the long-term mean, or a more gradual approach to the zero frequency of occurrence coordinate than the normal distribution.

Lognormally distributed data can arise either where the percent reduction is physically bounded (e.g., 100 percent removal) or when the long-term average approaches the maximum achievable level of control in emission reduction. For example, SO_2 emissions from FGD systems generally can be represented by a lognormal distribution. If the FGD system is averaging 90 percent removal, then the long-term mean outlet emission level will be 10 percent of the inlet mean. It is well known that scrubbers, due either to natural variation or process upsets, can have daily average emissions considerably higher than the long-term mean. Although the data might average 90 percent removal, there can be no periods of removal greater than

100 percent to offset a day at 75 percent removal. Thus, the distribution will be skewed toward higher emissions. A similar situation can occur for NOx emissions as well. If the unit is operating at or near the minimum achievable emission rate, then process upsets or other factors affecting the NOx emissions could result in significantly higher emissions.

3. Time Dependency

The time dependency, or autocorrelation of the observed data must also be considered. Basically, autocorrelation is a measure of the relationship of the emission rate for one day to that of the previous day. If the day-to-day emissions are simply random, independent variations about the long-term mean, then no autocorrelation is present. The daily emissions for autocorrelated data, however, are related over time. If a given day is above the long-term mean, then the next day will also tend to be above the long-term mean. The converse is also true. Autocorrelated data therefore appear to run in stretches above or below the long-term mean.

Figure 1 illustrates non-autocorrelated and autocorrelated processes. Both traces (1a and 1b) have the same mean levels (1.00 lb NOx/MMBtu) and RSD values (15 percent). A first order autocorrelation coefficient (ρ) of 0.70 was used to construct Figure 1b. Visual comparison of the two figures reveals the basic characteristics of an autocorrelated process, i.e. several consecutive days above (or below) the long-term mean. In addition the non-autocorrelated data set is characterized by a higher random noise level. Figure 2 is an example of actual NOx continuous emission data over a period of 50 days of operation. Analysis of this data showed it to be time dependent with an autocorrelation coefficient of 0.63.

B. Impact of Statistical Parameters on Achievability of NOx Emission Standard

With the knowledge of the relative standard deviation and the autocorrelation coefficient, the achievable NOx emission level for a given compliance strategy can be estimated. Assuming a normal distribution model, analyses were performed to illustrate the impact of RSD and ρ on achievable emission levels when the long-term mean ranged from 0.4 to 1.2 lb NOx/MMBtu. These analyses used the criterion for the current standards which are based upon a 30-day rolling average with no more than one violation in ten years of operation. Use of the lognormal distribution would be expected to have only a minimal impact assuming RSD's less than or equal to 20 percent are encountered. For a given mean, autocorrelation and RSD, the use of a lognormal distribution would result in a slightly higher achievable standard relative to that for a normal distribution. The data in Table 1 illustrate that for a given RSD, the achievable emission levels increase as the time dependence of the data or autocorrelation increases. In addition as the RSD increases (ρ=constant), the achievable emission standard also increases for a given mean emission level. The ranges of the mean emission levels, RSD and ρ shown in Table 1 are representative of those which would be encountered when analyzing continuous NOx emission data.

The importance of properly characterized NOx emission data to correctly identify appropriate emission levels can be illustrated by comparing the mean emission levels with the achievable emission level from Table 1. Use of the long-term mean emission level to characterize achievable emissions would greatly understate the actual achievable levels which should be based upon time series analysis. For example, for CEM data resulting in a long-term mean NOx level of 0.4 lb NOx/MMBtu, the appropriate achievable emission level is 0.49 lb NOx/MMBtu on a 30-day average basis (assuming ρ=0.70 and an RSD=15 percent). In this case the achievable emission level is 23 percent above the mean emission level.

The most likely error that could result from applying statistical analyses to determine achievable NOx emissions would be to assume that the data were time independent (ρ=0) when, in fact, the data were dependent upon time ($0<\rho<1$) (i.e., the data were autocorrelated). For CEM data that were assumed to be independent (mean emissions = 0.4 lb/MMBtu, RSD=15 percent), an achievable 30-day average emission level of 0.44 lb/MMBtu would result. On the other hand, for the same CEM data which actually exhibited time dependence (ρ=0.7), the achievable 30-day average emission level would be 0.49 lb/MMBtu. Obviously, improper analysis of these data without accounting for autocorrelation could result in a standard (e.g., 0.45 lb/MMBtu 30-day average) that would be violated considerably more than once in ten years.

C. Effect of Sample Size Considerations on Estimates

The preceding examples assumed that an adequate sample size of continuous emission data were available to properly characterize the emissions. In addition to the statistical properties, the amount of data available has an important affect upon the accuracy of the actual achievable emission levels. Sample data are frequently used to estimate the probable characteristics of a larger data set (population). For example, two years of daily temperature readings may be used to calculate the mean annual temperature. Since two years obviously do not represent all of recorded history, the calculated value is only an estimate of the true annual average temperature.

Inherent in any estimated value determined from sample data is an associated level of uncertainty. This uncertainty is the direct result of not having data for every single data point in the population. The uncertainty in an estimate can be represented, for example, by a 95 percent confidence interval. Basically, this interval means that, if the measured average value is X, then it can be said with 95 percent confidence, that the true, or population mean is within the interval X ± k. The interval width, k, is a function of sample size, variability and autocorrelation. For constant variability, k decreases with increasing sample size and decreasing level of autocorrelation.

The data requirements for evaluating statistical parameters for autocorrelated data are generally higher than those for non-autocorrelated data. One of the principle time series references, Box and Jenkins (Ref. 10), recommends that a minimum of 50 data points (24 hour averages in this case) be used when modelling autocorrelated processes.

In order to better understand the effect of data requirements, several examples have been constructed. The first example illustrates the effect of sample size on point estimates of percent reduction before (pre-) and after (post-) boiler/burner modifications to reduce NOx emissions. This example was constructed for a hypothetical process whose overall NOx reduction is 60 percent, based upon one year of pre- and post-modification data. The effect of sample size on the estimate of process autocorrelation will also be illustrated with this example. The second example shows the effect of increasing sample size on the 95 percent confidence interval about the true percent reduction (50 percent in this example). The post-modification emission rate is assumed to be known exactly.

Referring first to Figure 1, notice that the dispersion about the mean level for non-autocorrelated processes is much more consistent than for autocorrelated processes. Any stretch of data for the non-autocorrelated process (Figure 1a) is generally much like any other. In contrast, the autocorrelated process (Figure 1b) tends to have periods when several consecutive days are above or below the long-term mean. Therefore, accurate determination of overall process performance is highly dependent on both the sample size and placement of the sample within the entire data set.

Figure 3 represents a model of NOx emissions from a steam generating unit in the baseline mode of operation prior to a hypothetical combustion modification to reduce NOx emissions (Figure 3a) and after the retrofit or modification has been made (Figure 3b). Prior to modification, the mean NOx emission level was 1.0 lb/MMBtu for one year of operation. The modification to the unit is, for the purposes of this illustration, assumed to result in a 60 percent NOx reduction to a mean emission level of 0.4 lb/MMBtu, also based upon one year of post-modification data. Both figures reflect RSD's of 15 percent and a first order autocorrelation of 0.70. Previous analyses on a limited amount of NOx emissions data conducted by the Utility Air Regulatory Group (UARG) have obtained RSD values ranging from 5 to 13 percent and first order autocorrelation ranging from 0.4 to 0.76.

To illustrate the effect of sample size on the the mean NOx emission level, data from the year of pre-modification emission data (Figure 3a) were used. Rolling averages were used to include all possible contiguous within-day averages of a specified duration. Figure 4, shows the effect of sample size on the variation of the mean emission level and the upper and lower 95 percent confidence limits for 10 and 50 day averages. The "true" or population mean (1.0 lb/MMBtu) can be used to determine the variation from this value for the three averaging times. Figure 5 shows the variations for these sample times. As can be seen, the variation from the "true" mean approaches zero as the averaging time increases.

If only a limited amount of data are available from which to determine the autocorrelation coefficient, it could be incorrectly concluded that the data are merely random, independent events. Assuming that only the first 10, 30 or 50 days of data are available from the data set shown in Figure 3 from which to estimate the autocorrelation coefficient, the effect of sample size on this estimate can be determined. Table 2 shows the statistical parameters determined from these data. As can be seen, the estimated value for the autocorrelation based upon the initial 50 days of CEM data agrees closely with the true value (0.70) as well as the value calculated using all 365 days from Figure 3. However, the estimate of the autocorrelation coefficient based upon only the first 10 days of data is not significantly different from zero [i.e., the 95 percent confidence interval (-0.38 to +0.88) in which the true autocorrelation coefficient (0.7) can be found includes zero]. Based upon this initial 10 days of data, it would be erroneously concluded that the NOx emissions are not autocorrelated. This further illustrates the need for at least 50 days of data for autocorrelated processes as recommended by Box and Jenkins. The conclusions drawn from these previous examples are also applicable to the post-modification data shown in Figure 3.

Clearly the estimated mean emission level is not only dependent upon the amount of data collected (i.e. 10, 30, 50, or 365 days) but also upon when, within the yearly period, the data is collected. Assuming that the "true" mean emission values are known for the full 365 days in the baseline pre-modification (1.0 lb/MMBtu) and the postmodification (0.4 lb/MMBtu) configurations, the effect on the estimated mean percent reduction can be determined when less than one year's worth of either pre- or post- modification data is available. This is illustrated in Table 3. If, for example, only 10 days of both pre- and post-modification data were used to make the estimate, the estimated mean reduction level could range from 36.5 to 81.1 percent, depending upon which 10 day stretch of data were used. In any case, the appropriate set of days to be selected would not be known a priori. If 10 days of pre-modification data are used with 50 days of post-modification data, the error in the "true" reduction level is reduced somewhat (ranging from 42.1 to 71.8 percent). The agreement with the "true" reduction level improves as the amount of collected data increases.

The second example illustrates that the effect of sample size on computed percent reductions in NOx emissions can also be determined by calculating, for various sample sizes, the width of confidence intervals which contain the true percent reduction. Tables 4 and 5 serve to illustrate this point. These Tables reflect only the uncertainty introduced by the amount of pre-modification data collected. Both tables were constructed assuming that the post-modification emission rate was determined exactly (not estimated from test data). In practice, there would be uncertainty associated with both the pre- and post-modification data. Consequently, the values in these tables represent artificially low limits.

Table 4 illustrates the effect of insufficient pre-modification data on the ability to adequately characterize the true achievable NOx reduction. The Table shows the 95 percent confidence values for 3, 5, 10, 30, 50 and 100 days of pre-modification data. Although the estimated percent reduction for each of these sample sizes is 50 percent based upon a 30-day average, the most that could be said based upon a limited set of data is that the true value lies within the limits of the confidence interval. It cannot therefore be concluded from Table 4 that the true percent reduction in NOx emissions is at least 50 percent, 30-day average, when insufficient pre-modification data is used. However, as the amount of pre-modification data increases, the confidence interval limits are reduced and approach zero as the sample size approaches 365 days.

In order to state that the true percent reduction in NOx emissions is at least 50 percent, 30-day average, at a specified confidence interval, then the lower confidence limit for the percent reduction must be at least 50 percent. This implies that the observed percent reduction during the test period must be higher than the target of 50 percent, 30-day average. Table 5 shows the minimum percent reduction for a given pre-modification sample size (assuming constant RSD of 15 percent) necessary to demonstrate, at a 95 percent confidence level, that the true percent reduction is at least 50 percent, 30-day average. For example, if only 10 days of pre-modification data were compared with one year of post-modification data, a measured reduction level of 57.5 percent would be required to show a 50 percent reduction within a 95 percent confidence interval. In this case and the 3, 5, 30, 50 and 100 day cases, the lower bound of the confidence interval will always be equal to a 50 percent, 30-day average reduction. Table 5 illustrates that a data collection program designed to demonstrate a specified percent reduction in NOx emissions will require achievement of a higher level of reduction in order to meet the program goals if only a small sample size is used. The level of demonstrated reduction required to meet the goals increases as sample size is reduced.

D. Effect of Load Scenario on Achievable Emission Standards

Unlike SO_2 emissions downstream of flue gas desulfurization equipment on utility and industrial boilers, NOx emissions are a function of a number of operational variables that are directly associated with the firing conditions under which steam is generated. The boiler itself is both the means for generating steam and, in essence, the emission control system. This dual role creates conditions under which a particular steam generation load scenario can result in low 30-day average NOx emissions while another scenario, for the same unit, might result in high 30-day average emissions. As will be pointed out in the following discussion, estimating the long-term achievable NOx standard from CEM data is only appropriate provided that both the variability of the NOx versus load characteristics and the range of likely load scenarios are taken into account. CEM data from Subpart D and Subpart Da utility boilers are used to illustrate this point.

EPA has collected considerable NOx emission data from several programs (Ref. 11 and 12). The data showed that the NOx characteristics varied greatly between units. Figure 6 illustrates the normalized NOx emission characteristics for some of these units. The NOx emission characteristics can be seen to vary from increasing to decreasing with load and combinations between. The load schedules (capacity factors and load range) for the units tested by EPA also varied widely. Table 6 shows the probabilities of operating below a load level for some of these units as well as two Subpart Da units. The average loads (capacity factors) varied from 61 to 98 percent of rated load while the load range (i.e. maximum-minimum load) varied from 5 to 66 percent. The average load for the Subpart Da units was generally higher than those for the older units. Similarly the load spread was smaller for the Subpart Da units.

Analyses of some of the units showed that the diurnal load variations were similar as shown in Figure 7. Using this type of diurnal load variation, models were formulated to illustrate the effect of the load scenario on the achievable NOx emission level. Both the NOx model and the load model reflect the natural time varying properties derived from continuous data collected on Utah Power and Light's Hunter Unit 2 (Ref. 15). Using these properties, hourly NOx and load were determined and achievable NOx emission levels calculated by applying a prediction error (random variation) to each of the calculated hourly values.

Table 7 shows the achievable NOx emissions for the simulated load scenarios shown in Figure 8 for two different NOx emission characteristic curves represented by "B" and "D" in Figure 6. Table 7 illustrates that depending upon both the NOx emission characteristics and the load scenario, vastly different achievable NOx emissions levels can result. This could have a significant influence on the evaluation of the appropriate achievable emission level, particularly if only one of the load scenarios were analyzed. For example, for NOx characteristic "D", the achievable emission level can vary from 0.54 to 0.34 lb/MMBtu for capacity factors ranging from 85 to 45 percent, respectively.

The significant points from this illustration are that the achievable NOx emission level based upon a 30-day rolling average is strongly dependent upon the NOx characteristics as well as the load scenario. In order to adequately characterize the achievable NOx emissions from a boiler, several months of data must be analyzed for load scenarios that bound the possible load capacity range that the boiler may experience in its lifetime. In practice, this may be difficult since this range may not be experienced until after many years of operation. In this event, it might be necessary to simulate the probable load scenarios based upon a set of actual continuous emission data as was done in the preceeding example. Analyses of this type for a number of boiler types would be necessary before a reasonable estimate could be made of the "true" achievable emission level for the boiler population. From a regulatory point of view, analyses of this type would be required to establish a new or revised standard based upon CEM data from operating units.

III. SHORT-TERM DATA ANALYSES AND INTERPRETATION

The value of short-term NOx emission test data from utility and industrial boilers is that it can provide indications of the importance of a number of variables on NOx emissions. These indicators can be used to establish the relative importance of the variables for altering the NOx emissions. Short-term data have, in the past, been useful to 1) evaluate research project goals, 2) establish utility boiler operating modes, and 3) configure the boiler for compliance with NOx emission limits or satisfy boiler manufacturers' guarantees. For instance, the utility boiler operator can use short-term data to assist in establishing a configuration that might identify a modification to satisfy an operating constraint. These modifications are generally for the purpose of correcting problems such as slagging or low steam temperatures and other similar operational difficulties. These modifications almost always effect the NOx emissions.

For the purpose of the following discussion, short-term data is defined as data gathered over a period that is insufficient to adequately define the time series statistical properties or the autocorrelation coefficient. Emission data of this type generally are derived from:

1) compliance/permitting tests,

2) boiler manufacturer guarantee acceptance tests,

3) boiler manufacturer shakedown testing,

4) boiler operator characterization testing,

and 5) parametric data acquisition from research programs.

Most of these data are acquired under more or less steady-state conditions used to investigate the influence of one particular parameter while holding other variables constant. The data in this case represent a "snapshot" of the emissions at one point in time under controlled conditions. In some cases the data are collected continuously over a portion of a day. In this case, while the boiler operating parameters are generally held constant during this time period, the collection time is too short to establish the time series statistical properties.

During short-term tests of the type described above, it is only possible to hold a limited number of the variables constant. Other variables related to maintaining normal and safe boiler operation are, for the most part, uncontrollable. These uncontrollable variables can have a significant effect on the short-term NOx emissions. The more important uncontrollable variables are:

1) furnace and convective pass tube cleanliness,
2) feedwater heater out-of-service conditions,
3) condenser cleanliness and leakage,
4) mill out-of-service conditions,
and 5) short-term coal variability.

As an example of the impact of uncontrollable variables, Figure 9 shows actual data from a large subbituminous coal-fired boiler. Due to the fact that coal-fired boilers are designed to be capable of operating with different sets of mills-out-of-service to facilitate their frequent maintenance requirements, it is possible to have load and other parameters held constant while mills are placed in and out of service. As can be seen, while the load and excess oxygen were held nearly constant, various mills were dropping in and out of service resulting in NOx emission variations on the order of 30 percent.

Data acquired from another subbituminous coal-fired utility boiler, shown in Figure 10, illustrates an attempt to characterize the influence of the mills-out-of-service pattern on NOx emissions while holding other variables constant. While attempts were made to normalize the load to minimize the data scatter, uncontrollable variables other than load still resulted in considerable scatter. Nevertheless, the characterization of the mill-out-of-service pattern indicated a trend of increasing NOx emissions as bottom mills were taken out of service. These data provide useful information for establishing preferred operational modes. On the average, the NOx varied approximately 30 percent depending upon which mills were in-service. Figure 11 illustrates another example of short-term data gathered on the same unit. This Figure shows the influence of overfire air port operation on NOx emissions. The data illustrate that the overfire air ports lose effectiveness beyond 60 percent open. However, the exact NOx level that might be achieved cannot be determined due to the short-term nature of the data scatter.

Figure 12 illustrates an example of short-term data from an EPA test program where excess oxygen is the parameter of interest. As can be seen, an exact relationship between excess oxygen and NOx could not be determined while the load and mills-out-of-service were varying. Only a general observation can be made that NOx emissions increase with increasing excess oxygen level.

As can be seen from the above illustrations, due to the effect of uncontrollable operating variables, an accurate, definitive characterization cannot generally be made with short-term data of this type. At most, where continuous compliance is the issue, short-term data can be used to examine general trends in NO_x emissions.

These comments regarding short-term data have important practical implications with respect to equipment guarantees. With the promulgation of the 1971 NOx NSPS, boiler manufacturers have typically been required to guarantee that the NOx emissions at maximum load will not exceed the NOx emission limitation specified in the standard. This was generally accomplished by a one-time test at high load over a period of several hours. This type of test to satisfy the guarantee was appropriate in light of the type of standard used at that time. However, though the 1979 Subpart Da and 1986 Subpart Db standards are now based upon continuous compliance at all loads and conditions, manufacturers guarantees continue to be met in many cases by a one-time, short-term test after commercialization. In light of the current continuous compliance requirements, this type of guarantee criterion offers little protection for the utility operator. That is, short-term data cannot be used to indicate the probability of compliance with either the Subpart Da or Db NOx standards since both are based upon 30 day rolling average emission data. As was shown above, only detailed time series analysis of continuous emission data for a prolonged period can provide an accurate estimate of the probability of compliance.

IV. CONCLUSIONS

A number of important conclusions can be drawn regarding the use of both long- and short-term NOx emission data. In general, properly analyzed along-term data can be useful for both regulatory purposes and engineering interpretations. Short-term data, on the other hand, only has usefulness in engineering interpretations to establish trends or indicators of technique effectiveness. The most important conclusions from a regulatory point of view are:

1. Both NOx (and SO_2) continuous emission data exhibit time dependent characteristics that influence the determination of achievable absolute emission levels as well as achievable reduction levels.

2. Time series analyses of NOx data used to establish achievable emission limits or achievable emission reduction levels are significantly effected by the continuous data sample size. Sample sizes less than 50 days in duration produce considerable error in the estimates of these limits or reduction levels.

3. The specific load scenario under which continuous NOx emission data is gathered significantly influences the estimate of the achievable emission levels. Operation at different capacity factors can result in vastly different achievable levels.

4. For the aforementioned reasons, short-term NOx emission test data provide no substantive information to support new or revised continuous NOx standards. These data provide "snapshots" in time and hence only gross indications of NOx reduction effectiveness.

5. In light of the current requirement for continuous compliance with emission standards, emission guarantees based upon short-term test methods may not be adequate to ensure compliance under all conditions.

As can be seen, it is important when analyzing CEM data for the purpose of establishing either achievable emission standards or achievable emission reduction levels, to take into account the time dependence of the data, the amount of data used to make the estimate and the load scenario under which the data are taken. Collection and analysis of CEM data collected without considering these factors could give misleading and incorrect results. Data collection programs utilizing continuous emission data should therefore be structured to obtain these data in a manner consistent with the analysis and compliance methodology discussed above, which is presently used by the environmental agencies.

ACKNOWLEDGMENT

The authors wish to acknowledge Mr. F. W. (Bill) Brownell of Hunton & Williams for his valuable assistance and guidance in the preparation of this paper.

REFERENCES

1. Federal Register, Vol. 40, No. 194 - Monday, October 6, 1975 60.45(C).

2. Standards of Performance for Electric Utility Steam Generating Units for which construction is commenced after September 18, 1978 [40 CFR 60, Subpart Da, promulgated June 11, 1979].

3. Proposed New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units [40 CRF 60, Subpart Db, proposed June 19, 1986].

4. Statistical Analysis of Wet Flue Gas Desulfurization Systems and Coal Sulfur Content Volume I: Statistical Analysis, Radian Corporation, August 18, 1983 EPA Report No. 68-20-3816.

5. NSPS for NOx Emissions from Industrial Boilers - Statistical Issues and Analysis of NOx Control System Data, Radian Corporation, March 15, 1983.

6. Continuous Emission Monitoring in the Electric Utility Industry, Electric Power Research Institute, EPRI CS-2860, February, 1983.

7. Assessment of the Long Term Precision of Continuous Emission Monitors, EPA/600/D-85-111 (1985).

8. Standards of Performance for New Stationary Sources; Fossil-Fuel-Fired Steam Generators; Proposed Rule [48 Fed. Reg. 48954, October 21, 1983].

9. Peduto, E. F., et al., "Characterization of NOx and SO_2 Control Performances; Southern Indiana Gas & Electric Company, A. B. Brown Unit 1," EPA Contract No. 68-02-3168, July 1983.

10. Time Series Analysis, G.E.P. Box and G. M. Jenkins (1976), Holden-Day Inc., p. 18.

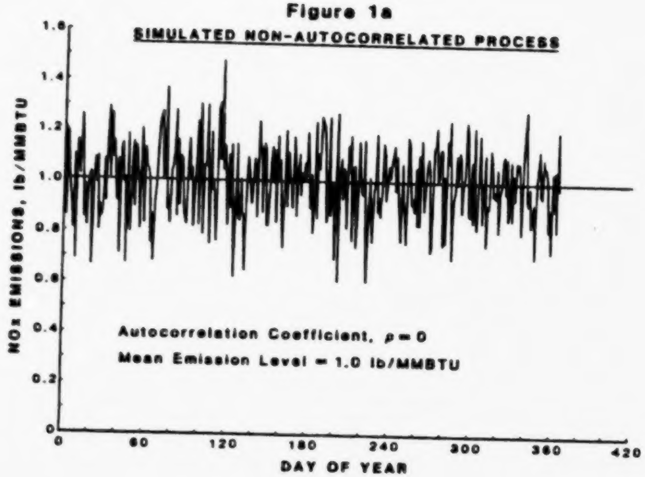
11. Cherry, S.S., "Analysis of Long-Term NO Emission Data from Pulverized Coal-Fired Utility Boilers," EPA Contract No 68-02-3175, Program Element No. C9BNIB, February, 1983.

12. Cherry, S.S., "Evaluation of Long-Term NOx Reduction on Pulverized Coal-Fired Steam Generators," EPA Contract No. 68-02-31, Work Assignment No. 9, July, 1984.

13. Analysis of CEM Data supplied by Tampa Electric Company.

14. Analysis of CEM Data supplied by Sierra Pacific Power Company.

15. Ferraro, et al., "Long Term Optimum Performance/Corrosion Tests of Combustion Modifications for Utility Boilers, Host Site: Utah Power & Light Company, Hunter No. 2" Exxon Research and Engineering Co., EPA Contract 68-02-2696, April 1985.



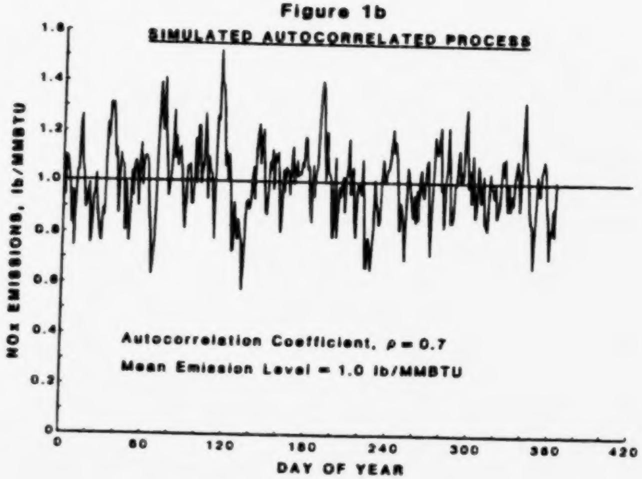


FIGURE 1 COMPARISON OF SIMULATED AUTOCORRELATED AND NON-AUTOCORRELATED EMISSION PROCESSES

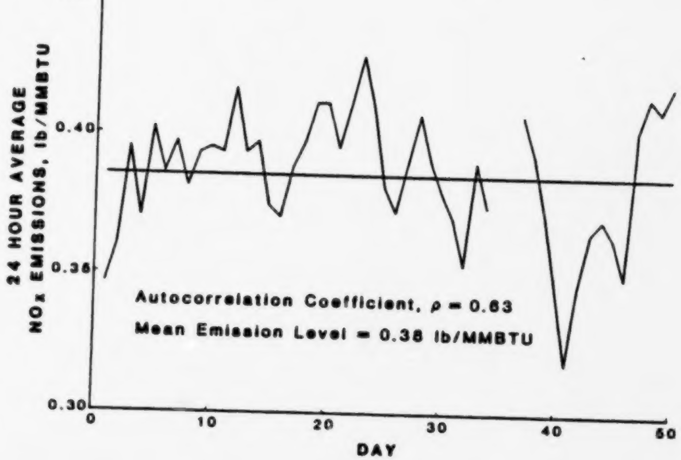


FIGURE 2 TIME SERIES ANALYSIS OF UTILITY BOILER OPERATION EMISSION DATA (REF. 9)

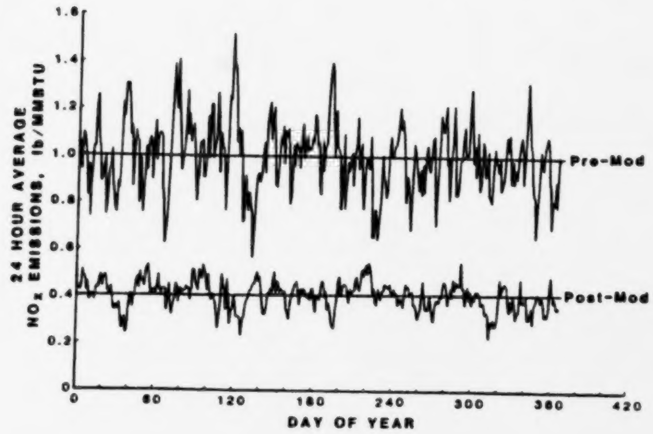


FIGURE 3 COMPARISON OF SIMULATED PRE- AND POST-MODIFICATION BOILER EMISSION CHARACTERISTICS

Figure 4a

10-DAY ROLLING AVERAGE EMISSIONS

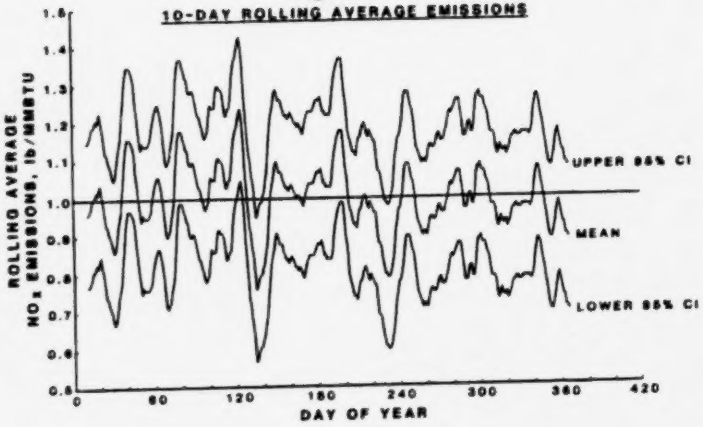


Figure 4b

50-DAY ROLLING AVERAGE EMISSIONS

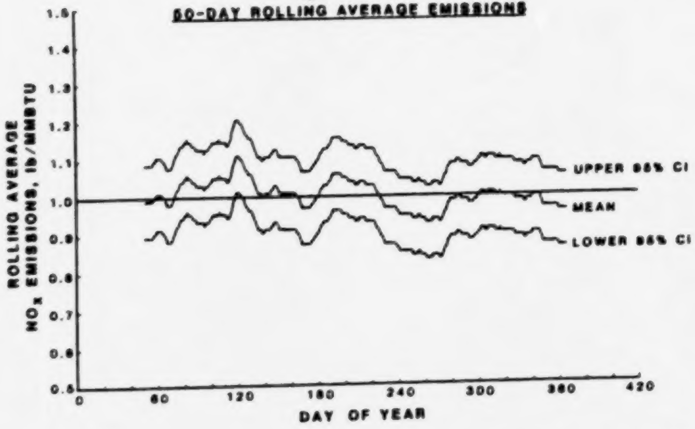


FIGURE 4 IMPACT OF AVERAGING TIME ON THE 95 PERCENT CONFIDENCE INTERVAL

Figure 5a

10-DAY ROLLING AVERAGE

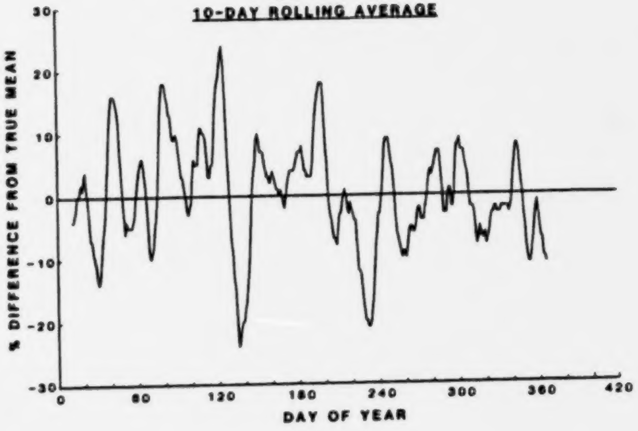


Figure 5b

50-DAY ROLLING AVERAGE

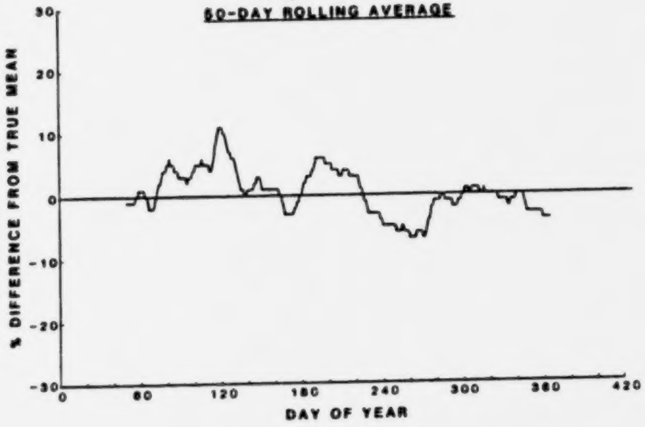


FIGURE 5 IMPACT OF AVERAGING PERIOD ON THE OBSERVED MEAN EMISSION LEVEL

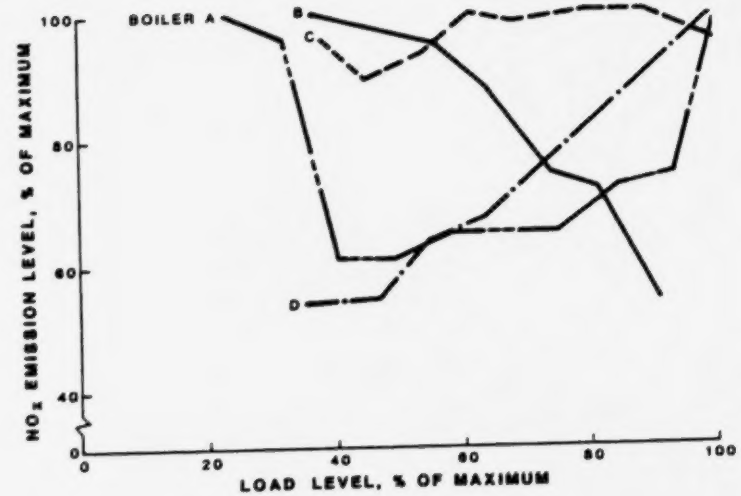


FIGURE 6 NOx CHARACTISTICS FOR UTILITY BOILERS

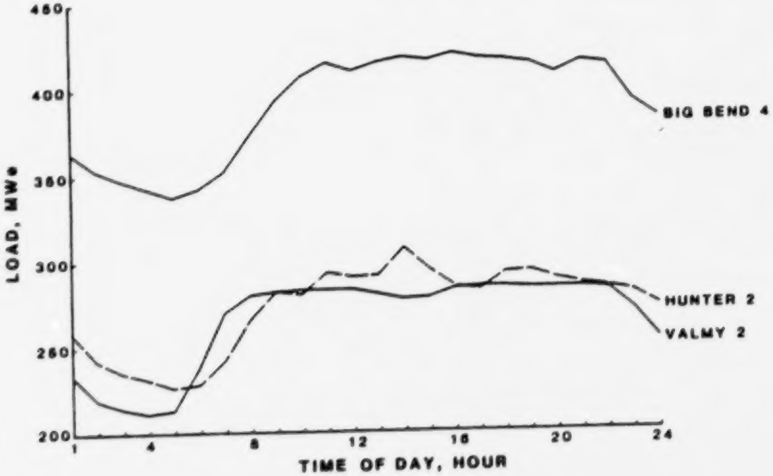


FIGURE 7 TYPICAL DIURNAL LOAD CHARACTERISTICS FOR UTILITY BOILERS

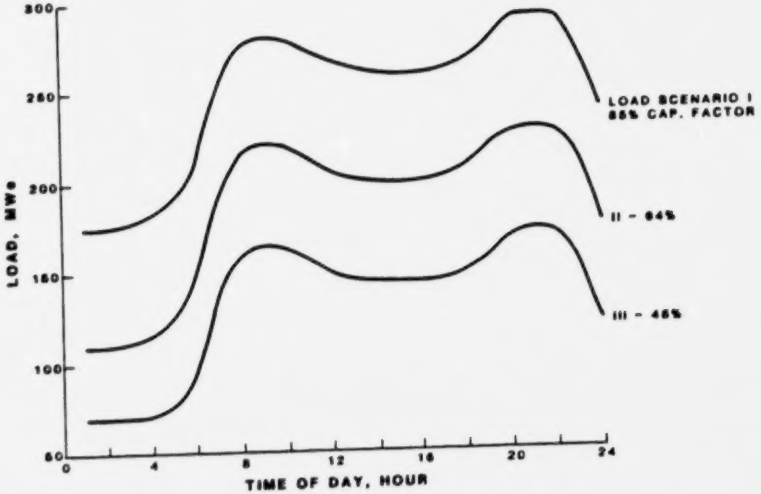


FIGURE 8 DIURNAL LOAD CHARACTERISTICS FOR THREE SIMULATED LOAD SCENARIOS

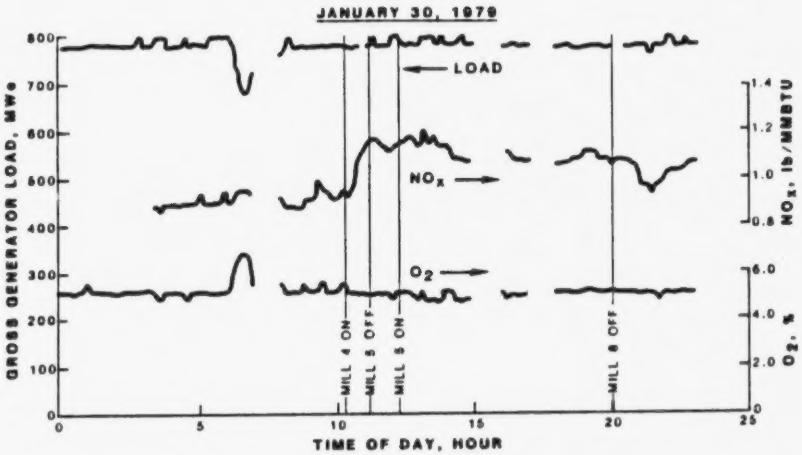


FIGURE 9 INFLUENCE OF MILLS-OUT-OF-SERVICE OPERATION ON DAILY NO_x EMISSIONS

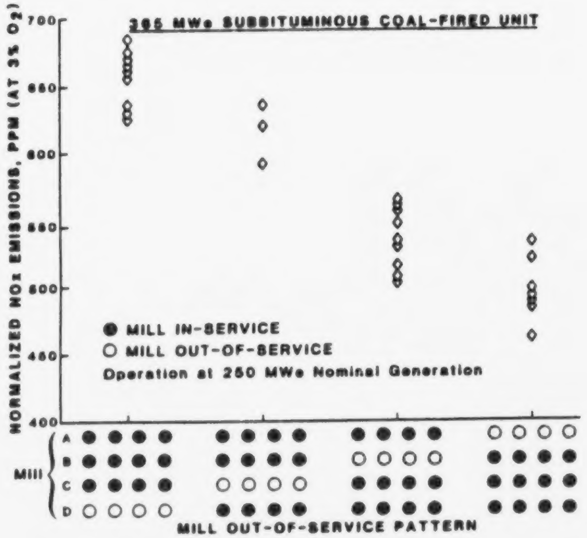


FIGURE 10 INFLUENCE OF MILL PATTERN ON CONSTANT LOAD NO_x EMISSIONS

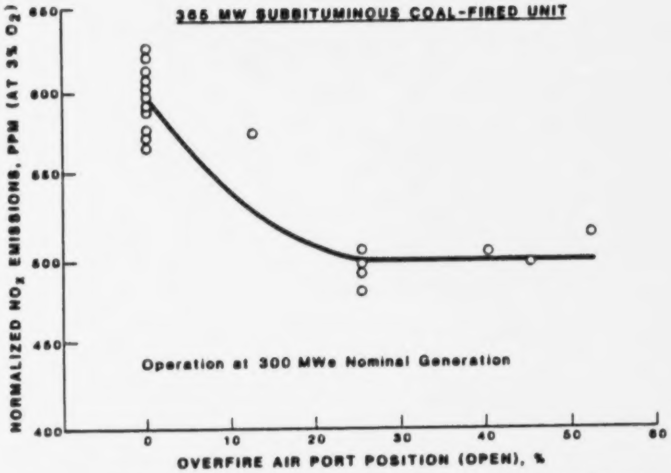


FIGURE 11 INFLUENCE OF OVERFIRE AIR PORT POSITION ON CONSTANT LOAD NO_x EMISSIONS

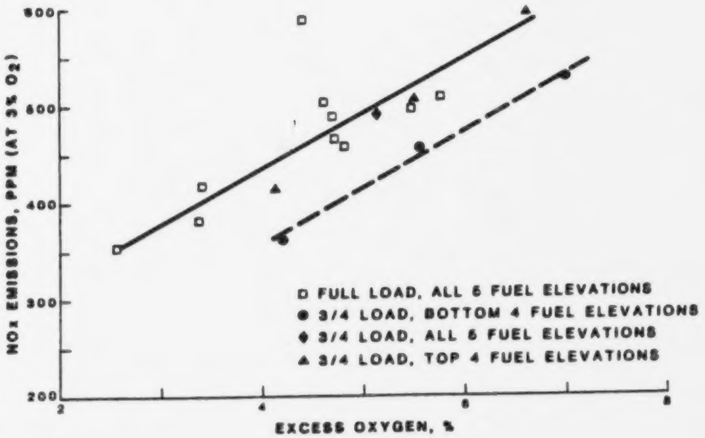


FIGURE 12 INFLUENCE OF EXCESS OXYGEN ON NO_x EMISSIONS AT VARIOUS LOADS AND MILL PATTERNS (REF. 15)

TABLE 1 EFFECT OF LONG-TERM MEAN, RSD AND AUTOCORRELATION ON ACHIEVABLE 30-DAY ROLLING AVERAGE NO_x EMISSION STANDARD[a]

Mean[c] Emission Level	RSD = 5%[b]			RSD = 15%		
	$\rho=0$[d]	$\rho=0.35$	$\rho=0.70$	$\rho=0$	$\rho=0.35$	$\rho=0.70$
0.4	0.41	0.42	0.43	0.44	0.45	0.49
0.6	0.62	0.63	0.64	0.66	0.68	0.73
0.8	0.83	0.84	0.86	0.88	0.91	0.97
1.0	1.03	1.05	1.07	1.10	1.14	1.22
1.2	1.24	1.25	1.29	1.31	1.36	1.46

[a] Average 1 violation per 10 years (normal distribution).

[b] Relative standard deviation for 24-hour average NO_x emission rate.

[c] Long-term mean NO_x emission rate, lb NO_x/MMBtu.

[d] R = First order autocorrelation for 24-hour average NO_x emission rate.

TABLE 2 EFFECT OF SAMPLE SIZE ON ON ESTIMATION OF PROCESS AUTOCORRELATION (PRE-MODIFICATION DATA)

Number of Days	Estimated Autocorrelation	S.E.[a]	95% Confidence Interval	
			Lower	Upper
365	0.68	0.05	0.58	0.78
First 50	0.66	0.14	0.41	0.93
First 30	0.56	0.18	0.21	0.91
First 10	0.25	0.32	-0.38	0.88

[a] S.E. is standard error estimate for the autocorrelation.

TABLE 3 IMPACT OF SAMPLE SIZE ON THE ERROR IN ESTIMATION OF THE TRUE EMISSION REDUCTION LEVELS

Post-Retrofit ▶ Pre-Retrofit ▼	Percent NO_x Reduction[a]				
	Lowest 10 Days	Highest 10 Days	Lowest 50 Days	Highest 50 Days	One Year
Lowest 10 Days	61.8	36.5	46.1	42.1	51.3
Highest 10 Days	81.1	60.8	71.8	64.8	67.3
Lowest 50 Days	69.6	47.9	63.1	53.3	57.7
Highest 50 Days	74.5	55.9	69.1	60.8	64.5
One Year	71.1	51.7	65.6	56.7	60

[a] Predicted from mean values, %.

TABLE 4 EFFECT OF SAMPLE SIZE ON WIDTH OF 95% CONFIDENCE INTERVAL FOR NOx PERCENT REDUCTION

Sample Size	Lower CI	Estimated % Reduction	Upper CI
3	0	50%	67.9%
5	25.7%	50%	62.3%
10	36.0%	50%	59.0%
30	42.7%	50%	55.6%
50	44.5%	50%	54.5%
100	46.3%	50%	53.2%

TABLE 5 SAMPLE PERCENT REDUCTION REQUIRED TO DEMONSTRATE 50% NOx REDUCTION AT 95% CONFIDENCE LEVEL

Sample Size	% Reduction
3 Days	63.8%
5 Days	60.0%
10 Days	57.5%
30 Days	54.8%
50 Days	53.8%
100 Days	52.7%

TABLE 6 LOAD CHARACTERISTICS FOR CEM DATA FROM UTILITY BOILERS

Unit Name		Rated Load	Log Probabilities						
			Percentage of Data				Percentage of Data		
			<10%	<50%	<90%	<99.9%	<10%	<50%	<90%
	Ref.		Upper Load Limit, MW				Upper Load Limit, % Rated Load		
Muskogee Unit 4	11	550	180	400	500	540	33	74	92
Nebraska City Unit 1	11	575	230	395	540	625	36	63	86
Council Bluffs Unit 3	11	720	450	640	680	740	60	86	91
Homer City Unit 3	11	680	670	690	700	700	95	98	100
Mill Creek Unit 3	11	425	100	275	400	450	22	61	88
Unit A	11	350	150	220	310	360	41	61	86
Unit B	11	350	170	270	330	360	47	75	91
San Juan Unit 1	11	360	225	315	345	365	61	86	94
Hunter Unit 2 (1983)	12	425	250	300	325	425	58	70	76
Hunter Unit 2 (1982)	12	425	200	300	380	425	47	70	89
Unit B	12	360	175	300	330	360	48	83	91
Unit C	12	360	160	280	325	360	44	77	90
Gentleman Unit 1	12	680	265	450	580	640	38	66	85
Big Bend Unit 4	13	450	321	411	446	456	71	91	99
Valmy Unit 2	14	290	183	280	287	290	63	96	98

TABLE 7 ACHIEVABLE NO_x EMISSIONS FOR VARIOUS LOAD SCENARIOS

Load Scenario[a]	NOx Character.[b]	Maximum Load	Minimum Load	Variation[c]	Cap. Factor[d]	Average NOx	Achievable NOx
I	B	285	175	38%	85%	0.41	0.44
II	B	228	109	51%	64%	0.42	0.46
III	B	172	70	58%	45%	0.46	0.51
I	D	285	175	38%	85%	0.52	0.6
II	D	228	109	51%	64%	0.4	0.46
III	D	172	70	58%	45%	0.28	0.33

[a] See Figure 8

[b] See Figure 6

[c] [(Max Load - Min Load)/Max Load] * 100.

[d] $\int_0^t \frac{\text{Load}(t)}{\text{Max Load}}\,dt$

ENGINEERING AND ECONOMIC ANALYSIS OF RETROFIT LOW-NO_x COMBUSTION SYSTEMS

R.A. Lisauskas
R.J. Snodgrass
Riley Stoker Corporation

S.A. Johnson
Physical Sciences, Inc.

D. Eskinazi
Electric Power Research Institute

ABSTRACT

The feasibility of retrofitting low-NO_x combustion controls on four different utility wall-fired boiler designs has been evaluated. This evaluation included an engineering analysis of all equipment modifications, and a cost estimate for each retrofit option. Consideration was given to boiler physical limitations and operating constraints, as well as achieving NO_x reduction. NO_x emission predictions were based on correlations developed from both field installations and large pilot-scale combustion tests. The following low-NO_x combustion processes were evaluated:

- Low-NO_x burners
- Conventional air staging (Overfire air)
- Advanced air staging (Overfire air)
- Reburning

Costs are presented in terms of $/kW, mills/kWh, and $/ton of NO_x removed. The cost of retrofit NO_x controls were found to vary with unit size and retrofit complexity. Depending on the level of boiler modifications required, the capital cost of retrofit combustion controls can vary from less than $3/kW to more than $20/kW.

1. INTRODUCTION

Retrofit combustion controls have become especially important with the increasing implementation of advanced NO_x control techniques in both Japan and West Germany. Because of the limited retrofit NO_x control experience within the United States, little is known about the cost of such controls for all but a few boiler configurations. Consequently, the Electric Power Research Institute has sponsored a number of programs to develop NO_x control options tailored to individual boiler designs. This paper summarizes the results of one such program to evaluate the performance and cost of low-NO_x retrofit combustion controls for wall-fired utility boilers.

Post combustion flue gas treatment processes, such as selective catalytic reduction (SCR), have been installed on over 30 oil and coal-fired Japanese utility boilers. Up to 80% NO_x reduction has been demonstrated on low-sulfur coal using SCR. The capital cost of SCR for new coal-fired boilers has been estimated at \$50-\$100/kW (1). Operating costs, which are highly dependent on catalyst life, can range from 8 - 14 mills/kWh. One of the basic premises of this evaluation was that combustion controls, which can achieve a substantial degree of NO_x control, are more cost effective than post combustion controls.

Combustion NO_x controls have, with a few exceptions, been applied only to new utility boilers. In order to obtain performance and operating criteria on various control techniques, pilot scale combustion tests were performed on several advanced combustion systems in a 100×10^6Btu/hr test furnace. Tests were conducted on a single Riley Controlled Combustion Venturi[1] (CCV) low NO_x burner in combination with other combustion modification approaches such as overfire air and reburning (2). The integration of low NO_x burners with advanced techniques was considered for those situations where low NO_x burners alone do not provide the desired level of control. A summary of pilot test results comparing the performance of various combustion controls on four coals is shown in Figure 1. Average pilot scale test results correlated well with limited full-scale burner data (3). The tests confirmed that up to 50% NO_x reduction can be achieved with single stage low NO_x burners. Up to 75% NO_x reductions were achieved when a low NO_x burner was used in combination with overfire air or reburning.

Combustion modifications by their nature, must be carefully integrated with the design and operation of the boiler. This paper focuses on the feasibility of retrofitting these combustion control techniques to full-scale utility wall-fired boilers.

2. APPROACH

The overall objective of the feasibility study was to identify and quantify technical and economic issues associated with retrofit NO_x combustion controls. It involved estimating the relative cost of each retrofit option, and determining the effect of boiler size and configuration on both performance and cost. The impact of combustion modifications on boiler operation requires careful consideration of a number of technical issues including: NO_x emission scale-up, design of OFA and reburn fuel injection equipment, combustion efficiency, flame stability/scannability, combustion and steam-side control, fireside corrosion, fouling and slagging, and safety code compliance. Because of their complexity, not all of these issues could be fully resolved in the pilot scale tests.

---

[1] Protected by U.S. Patent No. 4,479,442

Control options, which provide different levels of NO_x reduction and require different amounts of boiler modifications, were selected for evaluation. These options included low-NO_x burners; and low-NO_x burners combined with other control methods such as conventional overfire air, advanced overfire air, and reburning. Low-NO_x burners are based on the controlled mixing of fuel and air to influence the fate of fuel-bound nitrogen released from coal during the early stages of combustion. The CCV burner accomplishes this through a patented venturi coal nozzle/spreader design. Low-NO_x burners combined with overfire air provides the next level of control. Overfire air (OFA) is one method of achieving two staged combustion. Conventional overfire air, or air staging involves the diversion of up to 30 percent of the boiler's total air requirement to injection ports located above the top row of burners. Advanced OFA is applied in a manner similar to conventional OFA but with up to 50% of the total combustion air directed to the upper furnace. Reburning involves the injection of both fuel and air to the upper furnace creating a secondary combustion zone. The reducing environment formed by the secondary fuel rich combustion zone serves to destroy NO_x formed in the lower furnace. Reburning was the most complex retrofit option considered. It has the advantage of being able to operate with a fuel lean primary combustion zone thus minimizing the potential for slagging and fireside corrosion in the lower furnace.

Engineering and economic analyses were performed for each of these control options on selected pulverized coal wall-fired boiler retrofit case studies. Design factors such as steam capacity, age of the unit, firing system (front versus opposed), burner location, furnace geometry and distance from the top burner row to the furnace exit were considered. Based on these criteria four wall-fired boiler cases were selected for analysis:

Case A - 140 MW, front-fired, four burner rows, no OFA ports
Case B - 400 MW, front-fired, four burner rows, no OFA ports
Case C - 360 MW, opposed-fired, two burner rows, no OFA ports
Case D - 360 MW, opposed-fired, three burner rows, with existing OFA ports

Each of these cases offers a different level of retrofit adaptability. Simplified drawings of each of boiler design case are shown in Figures 2 and 3. For purpose of analysis each of these boilers was assumed to be equipped with pre-NSPS Riley Flare burners firing a high volatile bituminous coal.

3. ENGINEERING FEASIBILITY

For each case study an engineering analysis was performed on the entire boiler system. Fuel supply and combustion systems, as well as emission characteristics were reviewed to determine the applicability of each retrofit option. The impact on furnace design, convection surface, auxiliaries, and boiler performance were also evaluated. The general arrangement of the boiler was reviewed for clearances and structural supports. In addition, general guidelines and equipment requirements were developed for each retrofit option. These requirements are summarized in Figure 4. It was not the purpose of this study to fully evaluate all of the consequences of combustion retrofit controls on boiler operation. However, based on the pilot scale tests and limited field experience, concerns such as flame stability, corrosion, fouling and slagging, and steam temperature control appear to be manageable.

Low-NO_x burners were the central element in all combustion control options considered. In general, low-NO_x burners require only a minimum amount of boiler modifications. Such burners can be designed to fit within existing burner openings and windboxes. The relative ease of retrofitting more advanced control options, however, is strongly influenced by boiler physical interferences such as buckstays, headers and downcomers. These interferences can limit available locations for overfire and reburn fuel injection ports. While it may be possible to relocate such equipment, the associated cost and potential impact on the structural integrity of the boiler can be prohibitive. Consequently, we attempted to limit the amount of pressure part changes to the boiler.

Low NO_x Burners

Low-NO_x burners represent the most developed combustion control option evaluated. Actual field experience with the Riley CCV burner was used to identify important retrofit issues. The following burner design questions were addressed during the engineering evaluation:

1. Are the existing burner openings large enough to allow for changes in coal nozzle, air register or burner throat design without requiring pressure part changes?

2. Is the furnace firing depth sufficient to contain potentially longer, low-NO_x flames? Furnace wall flame impingement can result in furnace slagging, fireside corrosion and poor combustion efficiency.

The CCV burner was designed to be retrofit into existing burner openings with a minimum of changes. Only the coal head, nozzle and spreader must be replaced, along with any modification to the burner refractory throat. Another consideration was the complexity of the burner retrofit. Depending on the age of the unit and the condition of the firing equipment it may be desirable, or necessary to replace the entire burner. For this reason both a simple retrofit (coal head, nozzle and spreader) and a total burner replacement were evaluated. In either case small underfire air ports and side air ports were provided to assure an oxidizing atmosphere in the furnace hopper and along sidewalls, as well as to lower the increased windbox pressure caused by the change in burner settings.

Overfire Air

Studies have shown that overfire alone can reduce NO_x from 15 to 30 percent (4). Our own pilot scale tests (Figure 1) showed that additional NO_x reductions can be achieved when overfire air is used in combination with low-NO_x burners.

We initially assumed, based on work by Johnson et al. (5), that the optimum location for the OFA, to maximize NO_x reduction, was 0.8 seconds above the top burner row. In addition, a minimum of 0.5 seconds residence time was required above the OFA ports to achieve carbon burnout. In practice, most OFA ports are confined in location by the furnace configuration and the presence of major structural members such as buckstays. Generally, OFA ports are located approximately one burner spacing above the top row of burners, between two buckstays. All air staging ports were equipped with pneumatically actuated on/off dampers with a remote/manual station in the control room. Alterations to the combustion control and flame safety systems may be required to insure that the use of overfire air does not interfere with burner stability and performance. For cases requiring conventional amounts of overfire air (less than 30 %), the existing burner windbox was extended upward to supply air to the air staging ports.

Overfire air systems design concerns such as, furnace residence time, carbon burnout, and port location become even more critical for advanced staging systems. The major design difference is the requirement for a separate overfire air supply system. Since such a large portion of the combustion air (up to 50%) will be diverted to the OFA ports, it is necessary to exercise precise control over the amount of staging air. To achieve this a separate air supply system, including ductwork, flow control dampers and windbox, are required. Flow measuring devices in the new and existing ductwork would monitor air flow and determine the percentage of air diverted to the OFA ports. New control dampers in both the OFA system and existing ducts would be used to control these flows. Again, the combustion control system must be modified, and in this case the changes could be extensive.

Overfire air port design is a major consideration, for both conventional and advanced air staging systems. The effectiveness of overfire air is strongly dependent on achieving good mixing with primary combustion products. Key design parameters include OFA injection velocity, OFA port size, number, shape and location; and degree of staging. System pressure drop is also another important consideration in retrofit situations. In order to avoid the need for additional fans to boost system pressure, OFA port pressure drop was limited to 3 to 6 inches of water. Preliminary design guidelines developed in another EPRI study were used as the basis for the design analysis (6). In all of the four case studies the OFA ports were uniformly spaced and located only on the burner firing walls.

The addition of overfire air ports can potentially affect the structural integrity of the firing wall. In these cases provisions were made to transfer structural loads from the firing wall(s) to the side walls. A more detailed review of individual port design, as well as consideration of rectangular or eliptical ports, may result in a compromise on port design which does not require structural modifications.

Reburning

Our evaluation of reburning technology was limited to the use of coal as the reburn fuel. Many of the design considerations required for overfire air staging also apply to reburning. In addition, a minimum of 0.3 seconds residence time between reburn fuel injection ports and overfire air ports was established for design purposes.

For boilers with three or more burner rows, we assumed that the lower burner rows would be operated at a moderate air/fuel stoichiometry (80-100%), with a reburning zone stoichiometry of 60 to 70% of theoretical air. The advantage of operating under these conditions is that burner ignition stability can probably be maintained at lower burner loads, thus providing more turndown of the unit without removing burners from service. The top row can then be modified to operate as coal injectors, with the coal being transported from the pulverizer by primary air.

In the case of boilers with less than three levels of burners, fuel injection ports would have to be installed. Interstage air can be added over the first stage to help protect the waterwalls from possible corrosion and to aid in the reburning process (7). Overfire air is then injected above the fuel ports to complete combustion. As was the case with the overfire air, actual port locations were governed by physical constraints. Burner and pulverizer designs were reviewed to determine whether the top burner row could be used as reburning ports, providing 20-25% of the total fuel input. In some cases this may require overfiring lower burners, while derating the pulverizers serving the top burner row (reburn ports). The existence of dedicated pulverizers for each burner row is, therefore, highly desirable.

The most difficult, and expensive reburning case, which we evaluated, was Case C with only two burner rows. As a worst case scenario, we also assumed that new fuel storage and pulverizing equipment would be necessary on Unit, C along with the installation of both reburn and overfire air ports.

4. RETROFIT CASE STUDIES

Detailed engineering studies were performed for each of the retrofit options, on all four case study units. In each case proposal type drawings were prepared, as well as any design layout required to verify the feasibility of a retrofit. Material requirements, such as the amount of plate steel and tubing, and the amount of field work required, were also identified.

Unit A - 140 MWe Front-Wall Fired

Unit A is a 140 MWe natural circulation, superheat/reheat, balanced draft utility boiler, producing 950,000 lb/hr of primary steam. The retrofit of Low-NO_x burners is a relatively simple procedure. The existing 16 burners can be replaced with Riley CCV burners without making any changes to the burner tube bends. To meet burner velocity requirements, it was necessary to reduce the throat diameter by adding refractory. The windbox must be extended downward to accommodate the underfire air ports. Side air ports would also be provided to protect the side walls from any corrosion due to the Low-NO_x burners.

For both conventional and advanced staging, the overfire air ports must be added above the top burner row. In order to provide 0.8 second residence time between the top row of burners and the overfire air ports, the OFA ports should be 14 feet above the burners. Due to the presence of a buckstay, the ports must be located at 10 feet above the burners. This reduces the residence time to 0.6 seconds. In order to cover the entire cross-section of the furnace, nine overfire air ports were evenly spaced across the front wall of the furnace.

Under advanced air staging, overfire air would be supplied from a dedicated duct system. This system would take air from the existing burner air duct immediately after the air heater, and bring it to a separate windbox above the existing burner windbox. Total air flow control is provided by air dampers in both the new overfire air duct and the existing burner air duct. A flow meter would be installed to measure overfire air flow, while air to the burners would be measured by the existing venturi.

The application of fuel staging to this boiler would require all the modifications described for advanced air staging, plus the addition of intermediate air ports. For this configuration the top row of burners would be used as fuel injectors. This can be done since each of the four rows of burners operates from different pulverizer systems. Some air would be added through the intermediate air ports before the fuel injectors (about 10% of total combustion air), to improve carbon burnout, and provide additional protection from corrosion.

Unit B - 400 MWe Front-Wall Fired

Unit B represents a 400 MWe natural circulation, superheat/reheat, balanced draft utility boiler, producing 3,000,000 lb/hr of primary steam. It contains 24 pre-NSPS flare burners located in four rows served by three ball tube mill pulverizers. Except for the size of the equipment the retrofit of all four options to Unit B is similar to Unit A. In this case 13 overfire air ports would be provided above the top row of six burners. Again a compromise was required in the placement of overfire air ports, placing them 13 feet rather than the desired 18 feet, above the top burner row. Under reburning conditions the top row of burners would be used as fuel injectors and intermediate air ports would be added to improve carbon burnout and protect against corrosion. Pulverizer system changes would be required to match the pulverizers with three burner levels and one reburn fuel injection level.

Unit C - 360 MWe Opposed-Fired

Unit C is a 360 MWe natural circulation boiler producing 2,600,000 lb/hr of primary steam. A total of 24 burners are located in two rows on both the front and rear walls. The retrofit of Low-NO_x burners and advanced air staging to this unit is similar to units A and B. Limited space above the burners and the existence of only two burner rows makes fuel staging a complicated retrofit option.

For the advanced overfire air retrofit, the overfire air ports should be 19 feet above the burners to have 0.8 seconds residence time. This was not possible due to the superheater header on the front of the boiler, and the economizer hopper on the rear of the furnace. The ports, therefore, would be 12 feet above the burners which corresponds to about 0.5 seconds residence time.

The application of reburning technology to Unit C would require the installation of reburn fuel injection ports approximately 12 feet above the existing top burner row. This would place the installation of burnout ports in the area of the existing superheater header and economizer hopper. Therefore, major pressure part changes involving the superheater, economizer, and economizer hopper would be required. In addition to the required pressure part work, new coal feed and pulverizer systems would be needed to supply the reburn fuel injection ports. This case represents a worst case scenario for the application of reburning to wall-fired boilers.

Unit D - 360 MWe Opposed-Fired

Unit D is a 360 MWe natural circulation, superheat/reheat, balanced draft boiler, producing 2,584,000 lb/hr of primary steam. It has 24 burners, located in three rows on both the front and rear walls. Unit D is already equipped with overfire air. However, the existing system would require modification to improve the effectiveness of overfire air when used in combination with low NO_x burners. The original OFA port design is based on relatively narrow rectangular openings in the furnace wall. These existing ports have insufficient flow area for advanced OFA operation and the shape of the ports must also be changed for better jet penetration and mixing. The existing underfire air and side air ports are sufficient for corrosion protection. Due to the superheater header on the front of the boiler, the overfire air ports are located 11 feet above the burners. This corresponds to 0.6 rather than 0.8 seconds residence time.

Unlike Unit C the top row of burners would be used as reburning fuel injectors. Intermediate air ports would be added to improve carbon burnout and protect against corrosion.

5. NO_x PERFORMANCE

NO_x emissions were predicted for each of the four retrofit NO_x control options. The predictions are based on the pilot scale combustion tests supported by EPRI as well as U.S EPA and Riley sponsored pilot scale tests (3) and field tests performed by Riley. Uncontrolled NO_x emissions from the four case study units range from 700 to 830 ppm[1].

Full scale low NO_x burner performance was evaluated based on a correlation of emissions with a burner area heat release (BAHR) parameter shown in Figure 5. The BAHR is defined as the gross fuel heat input divided by the cooled surface in the main flame zone. The correlation shown in Figure 5 predicts the performance of a pre-NSPS Flare burner, and two versions of the low NO_x CCV burner. The difference between CCV burners is a result of differences in coal nozzle design. Nozzle Design No. 2 was developed for CCV burners used in two stage combustion systems. Under single stage operation this design results in higher NO_x emissions than design No. 1. For the four case studies evaluated, NO_x reductions on the order of 40% were estimated for low NO_x burners alone.

While the Low NO_x burner emissions can be correlated with a simple heat release parameter, more advanced combustion systems require a more complex analysis. Our pilot scale results revealed that under deeply staged combustion conditions NO_x was a function of first stage heat removal, as well as stoichiometry. This behavior is similar to results observed by Johnson, et al (5). A furnace heat transfer computer model was used to relate first stage heat removal in both the test furnace and the full scale utility boilers. The model was also used to determine the impact of various combustion modifications on furnace exit gas temperatures.

Figure 6 describes the trend of pilot scale NO_x emissions with first stage heat removal for both conventional and advanced amounts of staging. This curve was used to predict the incremental NO_x reduction when OFA is combined with low NO_x burners. For the four retrofit cases, total NO_x reductions of 56% to 59% were predicted for low NO_x burners with conventional air staging and 67% to 77% for low NO_x burners combined with advanced air staging. Based on our pilot scale test results (Figure 1) we assumed that emissions would be similar for both reburning and advanced air staging.

NO_x emission predictions for all boilers and retrofit options are shown in Figure 7. Emission of less than half the present NSPS standards are predicted for three of the four units with advanced overfire air, and reburning.

6. ECONOMIC FEASIBILITY

Equipment and modification costs were estimated based on the engineering analysis. Low-NO_x (CCV) burner costs were estimated for two retrofit situations: 1) assuming only the coal nozzle, coal head, and coal spreader need to be replaced; and 2) assuming an entire burner retrofit is required including register, front plate and refractory quarl. Actual retrofit requirements would be site specific. The required level of burner modification would depend on the age of the unit, the condition of the existing burners, and the compatibility of the retrofit burner with the original burner. For example, in one commercial CCV burner application only a coal nozzle/spreader replacement was needed, while in another both coal nozzle and air register modifications were required (8). Cost estimates for all staged combustion retrofit options assumed a complete burner retrofit.

---

[1] All reference NO_x emissions are part per million, dry and at 3% O_2, unless otherwise noted.

Equipment costs include material, shop labor, field labor, manufacturer's engineering, sales tax and freight. Estimates were prepared in accordance with normal proposal engineering estimating procedures. Fees, contingencies and operating maintenance costs were estimated according to EPRI "Economic Premises for Electric Power Generating Plants", issued December 15, 1982. The cost estimates are based on a Class II preliminary design. A sliding scale of process and project contingencies were used to reflect the various stages of development for each retrofit option. The calculation of 30 year levelized busbar cost are also according to the EPRI premises. All capital and operating cost estimates are presented in 1983 dollars.

Table 1 summarizes total capital costs and levelized power costs for the four retrofit options on each case study unit. Capital costs are plotted in Figure 8, versus unit size. For all cases there is an inverse relation of capital costs, expressed in $/kW, with unit capacity. Units C and D (both 360 MWe) were very close in costs for all options except reburning. In terms of ease of retrofit the Unit C reburning case reflects a worst case scenario. The additional cost of reworking the superheater header and economizer, and the addition of coal handling equipment increases the cost of reburning by almost a factor of three (18.3 $/kW vs. 53.2 $/kW). However, even with the high capital cost, the levelized power cost is only 2.4 mills/kW-hr for this worst case.

The sensitivity of these costs to changes in the economic assumptions was also considered. The change having the largest affect on capital costs is outage time for construction. We assumed in our analysis that some site work could be performed with the unit on line, and that all construction could be completed with a scheduled four to six week outage. If construction were to require an extended unscheduled outage, the cost of replacement power could increase capital costs as much as 100 $/kW based on replacement power costs of 45 mills/kWh.

A change in furnace exit gas temperature large enough to require derating of the unit could also increase levelized cost significantly. Again, replacement power cost is the largest contributing factor. Changes in boiler heat rate of 5% to 10% could increase levelized power cost 10 to 15 times, due to the increased cost of fuel. Increased maintenance and operation cost could increase levelized costs two to three times, requiring additional maintenance and operating personnel.

Another way to evaluate the cost of retrofit NO_x controls is in terms of their levelized cost in dollars per ton of NO_x removed. Levelized capital and O&M costs are summarized in Figures 9 and 10. It was assumed new technologies, such as advanced OFA and reburning, would require increased maintenance as a percentage (4%) of installed cost. Although the maintenance cost for low-NO_x burners would be considerably less, some increase is expected over conventional burners. Experience has shown that the mechanical condition of the burner equipment is more critical for low-NO_x operation. Annual maintenance costs for low-NO_x burners and conventional overfire air systems were estimated at 2% of installed cost. Sufficient controls were provided in the design and cost of each system so that no additional operating labor is anticipated for any of the four combustion systems evaluated.

These levelized costs in terms of $/ton of NO_x removed are an order of magnitude less, for even new NO_x combustion control technologies, than selective catalytic reduction.

7. CONCLUSIONS

The following major conclusions regarding retrofit low-NO_x combustion controls can be drawn from this engineering and economic evaluation:

1. Low-NO_x burners represent the lowest cost, combustion control system.
2. Low-NO_x burners with conventional overfire air is the next increment in control and cost. This control option can be as cost effective as low-NO_x burners alone when evaluated in \$/ton NO_x removed.
3. Although low-NO_x burner with advanced overfire air, or reburning, produce the lowest NO_x emissions, these combustion technologies have the most uncertainty in terms of both performance and cost.
4. There is an economy of scale, based on \$/kW, for all retrofit combustion options.
5. Major pressure part changes, new auxiliary equipment, and structural modifications can cause a three-fold increase in retrofit costs.
6. Retrofit costs are most sensitive to construction outage time and unit derating.
7. The capital and levelized power costs of retrofit combustion NO_x controls are significantly less than selective catalytic reduction.

REFERENCES

1. Maulbetsch, J., McElroy, M., Eskinazi, D. Retrofit NO_x Control Options for Coal-Fired Electric Utility Power Plants. Journal of the Air Pollution Control Association. Vol. 36, No. 11, November 1986, p1297.
2. Lisauskas, R., Snodgrass, R., Johnson, S., Eskinazi, D. Experimental Investigation of Retrofit Low-NO_x Combustion Systems. In: Proceedings of the 1985 Symposium on Stationary Combustion NO_x Control, Vol. I, 1986, pp12-1 to 12-18.
3. Lisauskas, R., Itse, D., Masser, C. Extrapolation of Burner Performance for Single Burner Tests to Field Operation. In: Proceedings of the 1985 Symposium on Stationary Combustion NO_x Control, Vol. I, 1986.
4. Thompson, R., Eskinazi, D., Afonso, R., Gilbert,G., Yang, R., and McHale, C. Laboratory Flow Model Studies to Improve Overfire Air Mixing. In: Proceedings of the 1985 Symposium on Stationary Combustion NO_x Control, Vol. I, 1986.
5. Johnson, S., Yang, R., and McElroy, M. Heat Transfer Modeling for Two-Stage Pulverized Coal-Fired Combustors. Paper presented at the Joint ASME/AICHE National Heat Transfer Conference, Orlando, Florida, July 27-30, 1980.
6. Lisauskas, R., McHale, C., Afonso, R., and Eskinazi, D. Development of Overfire Air Design Guidelines for Single Wall Fired Boilers. Paper presented at the 1987 Joint Symposium on Stationary Combustion NO_x Control, New Orleans, March 23-26, 1987.

7. Takehashi, Y., et. al. Development of Mitsubishi 'MACT' In-Furnace NO_x Removal Process. Paper presented at the U.S.-Japan NO_x Information Exchange, Tokyo, May 25-30, 1981

8. Penterson, C. Development of an Economical Low-NO_x Firing System for Coal Fired Steam Generators. Paper presented at the Joint Power Generation Conference, Denver, October 1982.

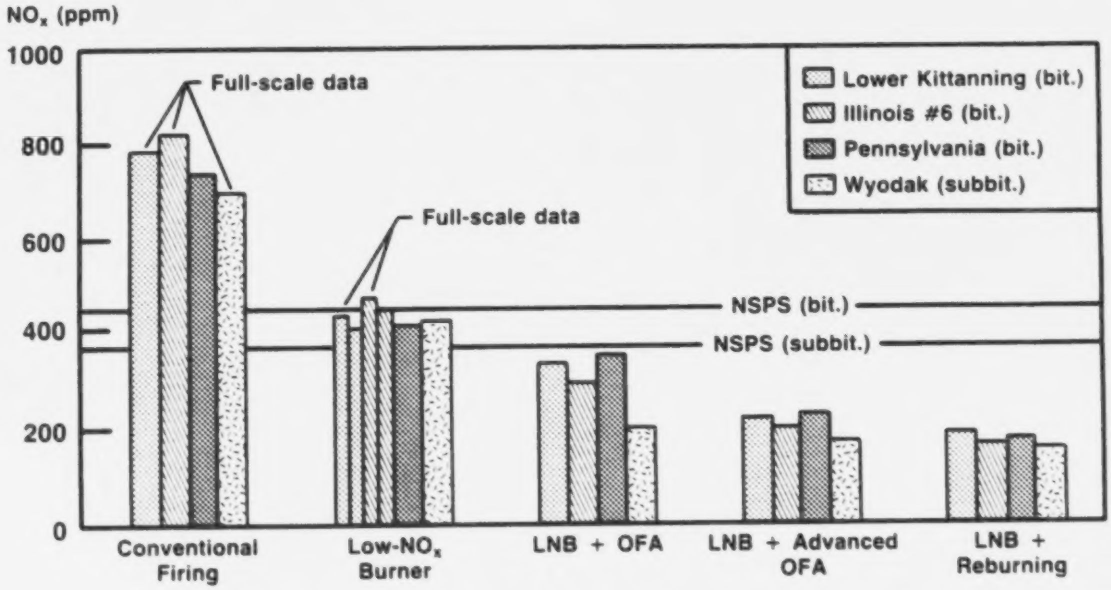


Figure 1. Summary of Pilot Tests Comparing NO$_x$ Reductions of Various Combustion Modifications

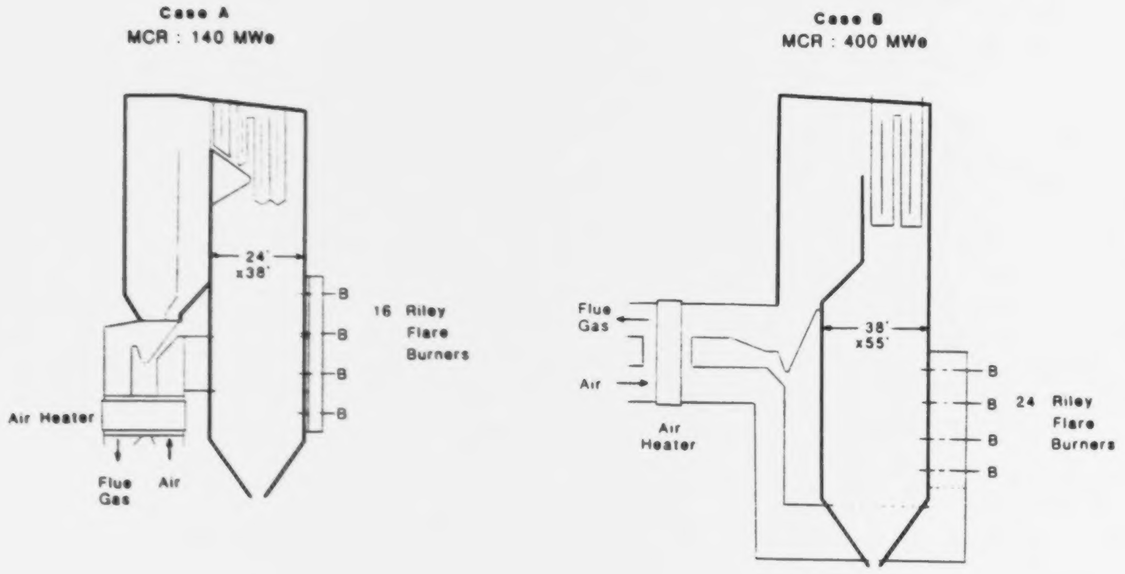

Case A
MCR : 140 MWe
24'
x38'
B
B
B
B
16 Riley Flare Burners
Air Heater
Flue Gas
Air
Case B
MCR : 400 MWe
Flue Gas
Air
Air Heater
38'
x55'
B
B
B
B
24 Riley Flare Burners

Figure 2. Front Wall-Fired Case Study Units

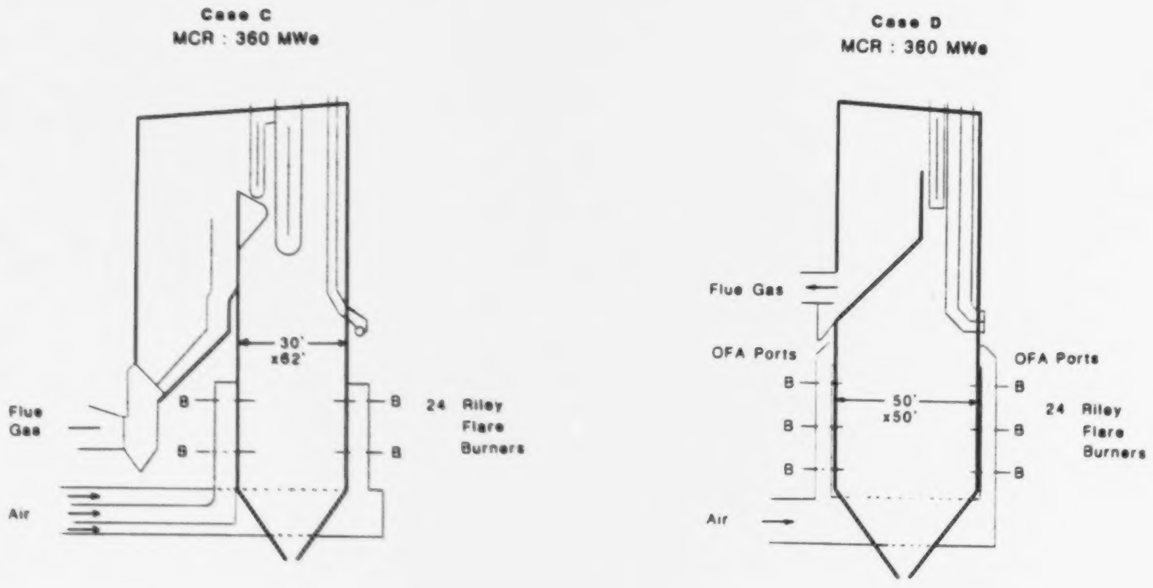
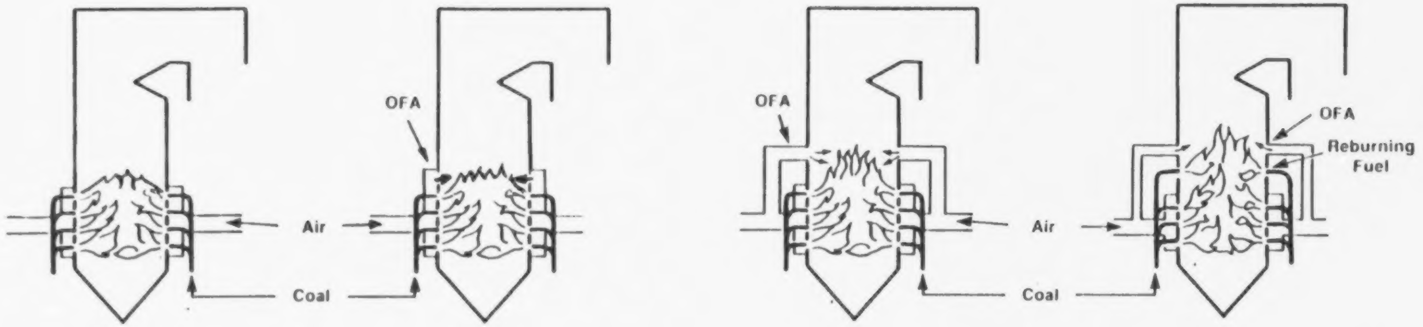

Case C
MCR : 360 MWe
30'
x62'
B
B
B
B
24 Riley Flare Burners
Flue Gas
Air
Case D
MCR : 360 MWe
Flue Gas
OFA Ports
OFA Ports
B
B
B
50'
x50'
B
B
B
24 Riley Flare Burners
Air

Figure 3. Opposed Wall-Fired Case Study Units



LOW NO$_x$ BURNERS

- Fuel Nozzle
- Coal Spreaders
- Modify Burner Throats (if Necessary)
- Register Replacement (Optional)
- Underfire Air Ports
- Tertiary Air Ports (multistaged burner)

LNB WITH CONVENTIONAL OFA

- Low NO$_x$ Burners
- OFA Ports
- OFA Dampers
- Windbox Extension

LNB WITH ADVANCED OFA

- Low NO$_x$ Burners
- OFA Ports
- OFA Dampers
- OFA Ductwork
- OFA Windbox
- Flow Measurement
- Control Dampers
- Burner Management

LNB WITH REBURNING

- Low NO$_x$ Burners
- OFA Ports
- OFA Dampers
- OFA Ductwork
- OFA Windbox
- Flow Measurement
- Control Dampers
- Fuel Ports
- Rework Coal Piping
- Burner Management
- Additional Coal Handling Equipment (if necessary)

Figure 4. Low NO$_x$ Combustion Techniques Which Were Evaluated for Technical and Economic Feasibility

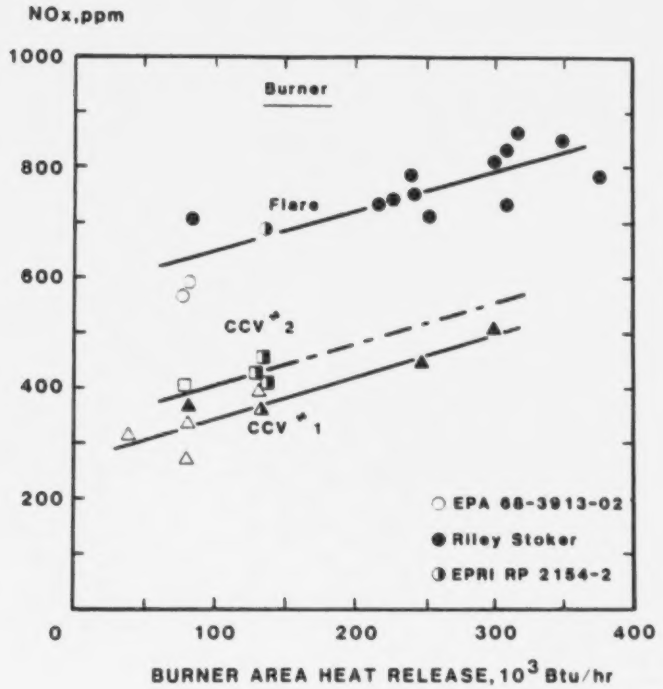


Figure 5. NO_x Prediction Curve for Low NO_x Burners (Base NO_x)

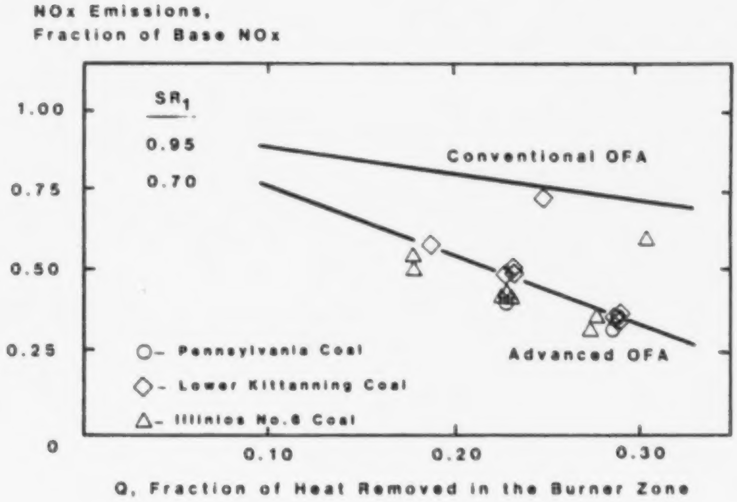


Figure 6. Prediction Curve for LNB with Overfire Air Staging Based on Data from Pilot Scale Combustion Tests

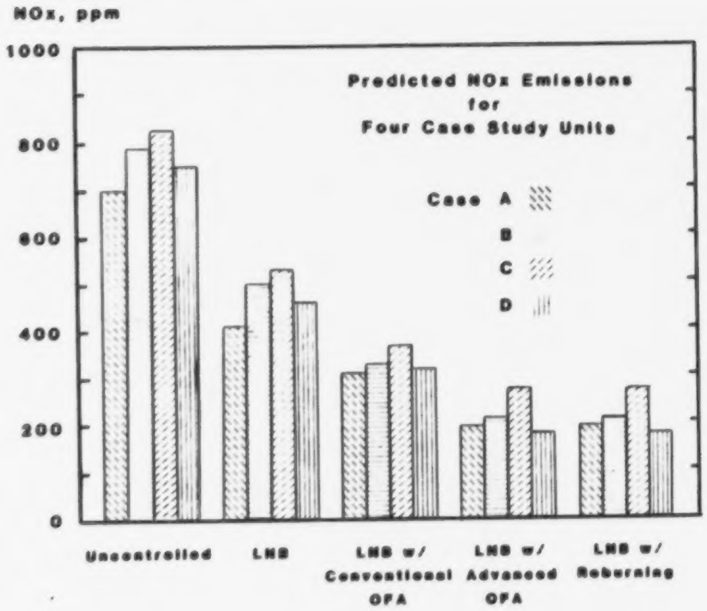


Figure 7. Predicted NO_x Emissions for Case Studies Compared to Uncontrolled Emissions

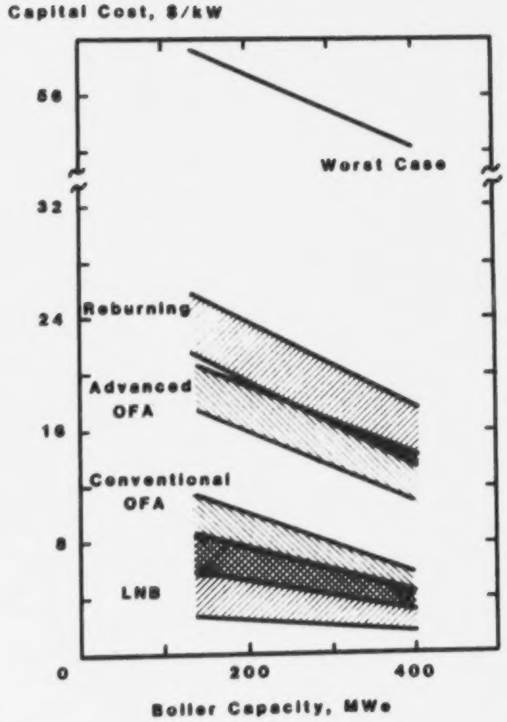


Figure 8. Projected Capital Costs of Low NO_x Combustion Techniques Showing the Effect of Unit Size

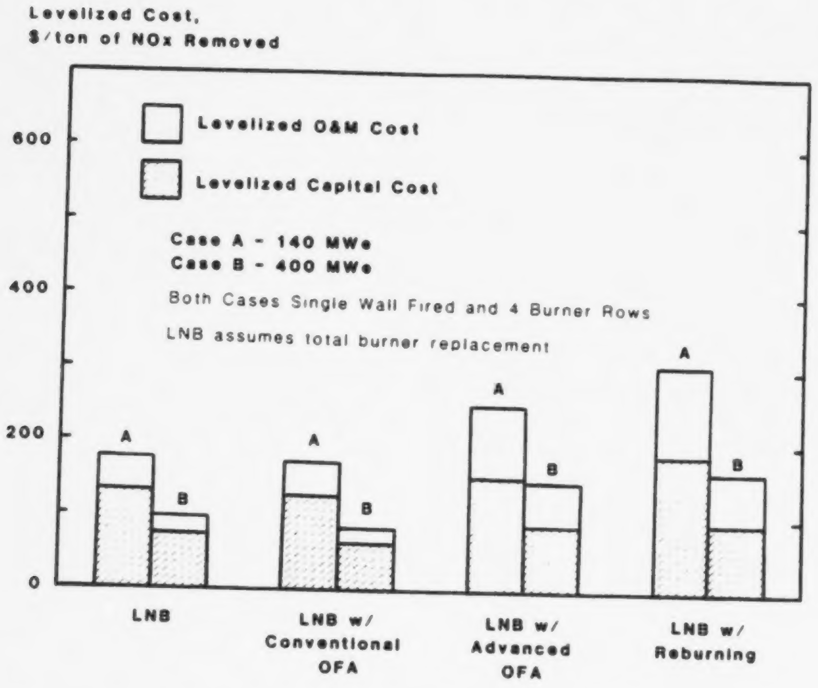


Figure 9. Comparison of Levelized Costs for Single Wall-Fired Boiler Cases. Both Cases Have Four Burner Rows.

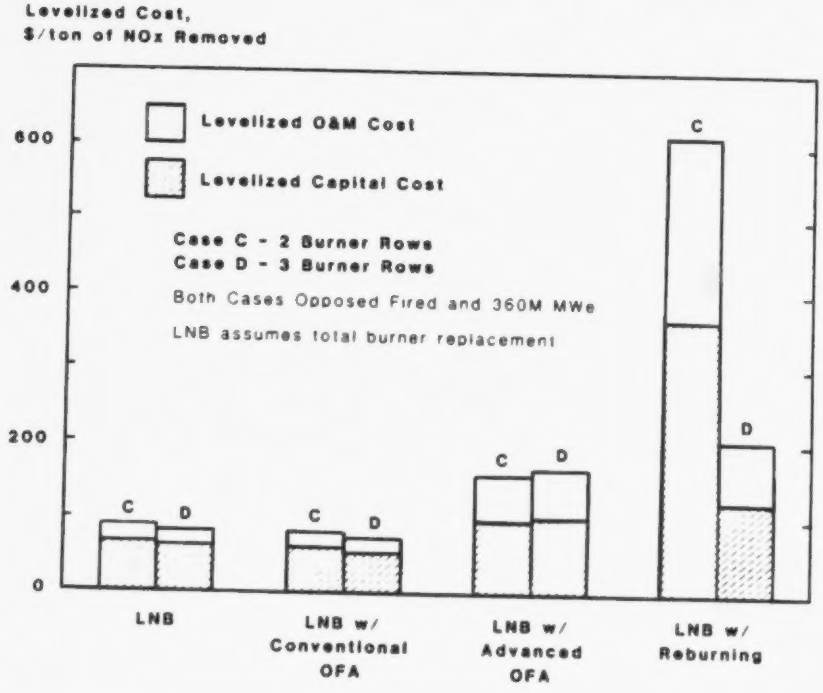


Figure 10. Comparison of Levelized Costs for Opposed Wall-Fired Boiler Cases. Both Cases Are Rated at 360 MWe.

Table 1

Summary of Economic Evaluation

	Case A		Case B		Case C		Case D	
	Capital Cost	Levelized Cost	Capital Cost	Levelized Cost	Capital Cost	Levelized Cost	Capital Cost	Levelized Cost
LNB								
Coal Nozzle Retrofit	2.8	0.10	1.4	0.05	2.1	0.08	1.4	0.05
Total Burner Replacement	8.7	0.32	4.6	0.17	5.4	0.19	4.8	0.17
LNB plus Conventional OFA	11.6	0.42	6.3	0.23	7.1	0.26	6.0	0.22
LNB plus Advanced OFA	17.8	0.80	11.3	0.51	13.8	0.62	14.9	0.67
LNB plus Reburning	21.5	0.97	13.5	0.57	53.2	2.40	18.3	0.82

Capital Cost - $/kW

Levelized Cost - mills/kW-hr(30-yr average)

THE INFLUENCE OF FUEL PROPERTIES AND BOILER DESIGN AND OPERATION ON NOx EMISSIONS

By:
J. H. Pohl and G. C. Dusatko
Energy Systems Associates
Tustin, California 92680

and

P. C. Orban and R. W. McGraw
Pennsylvania Electric Company
Johnstown, Pennsylvania 16907

ABSTRACT

Methods to predict the dependence of NOx emissions on coal properties, burner design and operation, and boiler design and operation are unreliable, complicated, or both. This paper determined the functional dependence of NOx emissions on a number of these parameters using data available in the literature. The functional dependences were then used to successfullu explain the changes in NO emissons observed for: (1) a 660 MWe boiler firing two bituminous coals with volatile contents of 26.3% and 18% as received, and (2) two wall-fired 30 MWe units and a 137 MWe tangential unit firing a single coal with a volatile content of 24% as received. The change in the NOx with coal, primary air velocity, load, and excess oxygen content were explained using the dependences derived in this paper.

INTRODUCTION

Emissions of NOx from boilers are currently difficult to predict. The difficulty arises because NOx emissions depend on many factors and information does not exist to adequately model all parameters which influence NOx emissions. However, the ability to predict the influence of parameters on NOx emissions is required to select fuels, burners, boilers, and operating conditions which minimize NOx emissions.

This paper reviews the influence of parameters on NOx emissions and the current predictive techniques, develops new techniques to predict the influence of the parameters on NOx emissions, based on mechanistic reasoning and empiricism, and compares predictions of the trends using these techniques with measurements of NOx emissions from one boiler firing two coals and two boilers firing the same coal.

NOx EMISSIONS

Emissions of NOx from coal-fired boilers has been shown to depend on the properties of the coal, the design and operation of the burner, and the design and operation of the boiler.

FUEL PROPERTIES

Nitrogen oxides have been shown to depend on the level of nitrogen in the coal (1). Later, coal nitrogen alone was shown not to completely account for the nfluence of coal properties on NOx emissions (2, 3). The NOx emissions were roughly correlated with HCN measured on small-scale combustion tests (3). Later, NOx emissions were shown to depend and were simply correlated with the nitrogen and volatile contents of the fuel (4). This simple correlation has now been verified for over one hundred coals and coal-water slurries from different parts of the world (5). The correlation has also been verified by independent investigators working in the Federal Republic of Germany (6, 7). The particle size has also been shown to have a minor influence on NOx emissions (8).

BURNER DESIGN

Burner design influences NOx emissions. Burners have been designed to control mixing, flame lift off, and flame length. These have included the delayed mixing burner developed by Energy and Environmental Research Corporation for the EPA (9) and its commercial testing by L&C Steinmuller (10), the dual register burner developed by Babcock and Wilcox (2), the split flame burner developed by Foster Wheeler (11), the controlled combustion venturi (CCV) burner developed by Riley Stoker Corporation (12), and the low-NOx concentric firing system (LNCF) developed by Combustion Engineering (13). Advanced coal burners are now being developed by Babcock Hitachi (14), Babcock and Wilcox (15), Hitachi Zosen (16), and IHI (17) which are capable of controlling NOx emission to near 100 ppm (dry, 0% O_2) when firing coal.

BURNER OPERATION

The operation of a burner was shown to affect the formation of NOx in the early 1970s (18, 19). Results of these trials sponsored by the EPA showed for unstaged conditions:

- Preheat increased NOx emissions
- High velocity and lifted flames increased NOx emissions

- Increase in primary stream stoichiometry increased NOx emissions

The relative swirl of the burner also affected NOx emissions. However, this dependence was difficult to quantify since swirl depends on outside-burner dimensions and cannot be consistently specified between different burners.

BOILER DESIGN

The boiler design has been shown to affect NOx emissions. The type of firing system used in a boiler has been shown to affect NOx emissions (3, 20). Also the heat release per burner zone area (HRBZA) has been correlated with NOx emissions for coals with similar properties (11-13).

BOILER OPERATION

The emissions of NOx from a boiler are influenced by boiler operation. Increased load (or heat release rate) and excess air have been shown to increase NOx emissions from boiler (20).

PREDICTION OF NOx

The ability to predict NOx emission from boilers is hampered by: (1) the complexity of the process; (2) the importance of local conditions in NOx formation; (3) the lack of knowledge of fuel nitrogen release, mechanisms, and kinetics; and (4) the inability to predict local mixing patterns in the complex flow of burners and boiler chambers.

Several approaches have attempted to predict portions of NOx emissions from boilers. These have included empirical correlations (11-14, 21, 22). The empirical approach taken so far can account for boiler design (HRBZA) and operating parameters (load and O_2 concentration). Limited scaling of NOx emissions from small-scale results or burner and boiler parameters have had some success. However, the scaling approach has been limited to considering the influence of only the chamber (23), the flame (24), and the flame and the chamber (25).

Complex mathematical models have been developed to predict NOx emissions from boilers. These models have had limited success in predicting NOx emissions from simple small-scale combustion chambers (26). However, the ability to predict NOx emissions using mathematical models is uncertain, probably not obtainable in the near future, and to achieve adequate prediction will require considerable effort and expense (27).

MECHANISM

The mechanism of NOx formation in boilers will be briefly reviewed to identify the influence of parameters on NOx emissions. Figure 1 shows that NOx formation can be divided between thermal NOx and fuel NOx.

THERMAL NOx

Thermal NOx is formed by gas-phase chain reactions initiated between oxygen radicals and molecular nitrogen. The fraction of thermal NOx emission in coal-fired flames and boilers is thought to be less than twenty percent of the total NOx formed (28). However, the amount of thermal NO depends on the conditions of the boiler, and thermal NOx will contribute a larger fraction of the NOx emissions from boilers using low-NOx burners.

Assuming only small amounts of thermal NO are made in the flame, reactions producing NO are irreversible, N radical concentrations are small, and the oxygen radicals are in equilibrium with O_2 yields:

$$\frac{d(NO)}{dt} = \frac{1.81 \times 10^{23}}{T} e^{\frac{-135,725}{RT}} (N_2)(O_2)^{1/2} \text{ ppm/sec} \qquad (1)$$

where (N_2) and (O_2) are in mole fractions, T is in °K, and R is cal/g.mole °K. According to Equation 1, thermal NO will be produced at a rate less than 10 ppm/sec when the temperature is less than 2500 °F when, (N_2) is 0.65, and (O_2) is 0.04. Temperatures less than 2500 °F are therefore unimportant for production of thermal NO.

Oxygen radicals may be in excess of equilibrium for a short distance beyond consumption of the hydrocarbons. In this case, the oxygen radical concentrations can be approximated by partial equilibrium considerations (29) as:

$$[O] = K_3K_4 \frac{[O_2][CO]}{[CO_2]} \qquad (2)$$

where K_3 and K_4 are the equilibrium constants for the reactions

$$H + O_2 = OH + O$$

and

$$CO + OH = CO_2 + H \quad .$$

The rate of formation of thermal NO under the conditions of super equilibrium can therefore be approximated as:

$$\frac{d[NO]}{dt} = 2 \times 7.6 \times 10^{13} e^{\frac{-75,500}{RT}} [N_2] K_3K_4 \frac{[O_2][CO]}{[CO_2]} \quad .$$

The contribution of thermal NO to NOx emissions should, therefore, be proportional to oxygen concentration between the half and first power. Figure 2 shows that NO emissions are closely approximated as dependent on oxygen concentration to the first power.

Thermal NOx, according to Equations 1 or 2, should be strongly dependent on the time-temperature history. The temperature depends on the heat release, the heat capacity of the gases, and the heat loss to the wall. The temperature over any region can be expressed as:

$$T_f = \frac{\text{lb/hr } (LCV + H_{air}) - E_f\, a_w\, (T_f^4 - T_w^4)\text{ EPRS}}{MC_p}$$

where T_f is the flame temperature, LCV is the lower calorific value of the fuel, H_{air} is the enthalpy of the preheated air, E_f is the emissivity of the flame, a_w is the absorptivity of the wall, EPRS is the effective projected radiant surface, and MC_p is the heat capacity of the gases and solids. This can be rewritten as:

$$T_f = \text{lb/hr} \frac{LCF}{MC_pEPRS} + \frac{H_{air}}{MC_pEPRS} - E_f a_w (T_f^4 - T_w^4) \quad . \qquad (3)$$

Equation (3) reduces to

$$T_f \quad \text{lb/hr} \frac{LCV}{MC_pEPRS} = HRZBA$$

under conditions when lb/hr (H_{air}/MC_pEPRS) is small and $E_f a_w (T_f^4 - T_w^4)$ is approximately constant. Figure 3 shows that the thermal NOx emission can be correlated with the heat release per burner zone area (HRBZA). However, the dependence of thermal NOx is stronger than the exponential dependence expected at HRBZA greater than 275 KBtu/sq.ft. The dependence of thermal NO emissions has therefore been approximated as the sum of the two exponential dependences.

FUEL NITROGEN

Nitrogen in the coal is partially evolved as volatile compounds in the flame region. This devolatized nitrogen participates in gas phase reactions. The remainder of the nitrogen remains and is oxidized with the char.

The extent of devolatization depends mostly on the properties of the coal and the flame temperature (30). The fraction of the volatile nitrogen converted to NOx depends on the fuel equilvalence ratio, temperature, and residence time in the flame (6, 7, 30, 31).

The influence of coal properties on nitrogen oxide emission for fixed temperature and different but fixed mixing conditions have been correlated (4). The degree of correlation for two conditions, a premixed flame and a premixed optimally staged flame, are shown in Figure 4.

The maximum flame temperature has been shown to influence the conversion of fuel nitrogen for fixed mixing conditions. Figure 5 shows the dependence of fuel nitrogen conversion on maximum flame temperature. Most of the data for German coals with very different properties shows an Arrhenius dependence on temperature. However, the correlation fails at temperatures less than 2100 °F (1150 C) and is less certain at temperatures greater than 2600 °F. The temperature range of reasonable correlation corresponds to the low range of temperatures measured in coal flames. The unexpected low conversion of fuel nitrogen at temperatures below 2100 °F may be caused by more nitrogen remaining in the char and incomplete combustion of the char (30).

Conversion of fuel nitrogen depends on the stoichiometry of and residence time in the flame region (5, 32). The amount of air in the flame region is the result of the primary air (32), air entrained in lifted jets (18), and air entrained in the flame region (33). Air used to carry the coal and that entrained in a lifted flame are equivalent.

For swirl burners, air entrained in the flame region depends on the momentum and orientation of the primary coal stream and the secondary air stream. Jet entrainment for parallel streams can be estimated (34). However, entrainment in a swirling flow is difficult to estimate because of the axial and tangential momentum and centrifugal forces which all contribute to entrainment. In addition, molecular mixing depends on the swirl and the burner dimensions.

The emissions of NOx from oil flames for most burner types have been successfully related to the flame volume (24). The flame volume is related to both flame residence time and flame stoichiometry. The flame residence time can be approximated as the flame volume divided by volumetric flow rate when the volume required to burn the volatiles (diffision controlled) is equal to the time required to mix oxygen with the volatiles. The molecular mixing time is longer and occurs when approximately three times as much air as required for stoichoimetric combustion of the volatiles is entrained.

Attempts to relate the flame volume to burner parameters (ratio of burner diameter to furnace diameter, fraction of heat extracted, burner pressure drop, and burner diameter) have been partially successful (24).

This work, however, estimates the influence of initial burner zone stoichiometry, primary air velocity, and swirl number on NOx emissions.

The initial primary air velocity affects the residence time in the flame. The flame residence time is related to the volume of the flame divided by the volumetric flow rate. The volumetric flow rate is

$$\text{Flow rate} \sim Vd^2$$

and the flame volume is

$$\text{Flame volume} \sim d^2 \cdot d \cdot d^n$$

where d^2 is related to the area of the flame, d is related to the entrainment length, and d^n accounts for the difference between entrainment and molecular mixing times. This results in an expression for the residence time of

$$t = d^{1+n}/V \quad .$$

Dr. Roy Payne has suggested that

$$t \sim d^{2.5}/V$$

for flames (35). The fuel NOx emissions will be reduced in the fuel-rich flame zone; therefore,

$$NO \sim V/d^{2.5} \quad .$$

High primary velocities will lift the flame. Air will be entrained in the lifted flame and effectively increase the primary air. The amount of air entrained in lifted flames can be estimated by techniques discussed below. The influence of primary stoichiometry is shown in Figure 6. The velocity at which a coal flame lifts off the burner, however, is difficult to estimate and more data is required before correlations can be developed.

The swirl number affects the flame by increasing mixng and by decreasing the residence times at swirl numbers less than 2. The influence of swirl on entrainment at x/d of 6 is shown to be exponential in Figure 6a, and the influence of swirl on flame residence time is shown to be linear in Figure 6b for swirl numbers less than 2.

For tangentially fired units, the residence time and stoichiometry of the flame zone can be estimated as the amount of air introduced in through the burners excluding overfire air, and the volume of the burner HRBZA zone divided by the heat release in the burner zone,

$$t \sim 1/HRBZA \quad .$$

CORRELATIONS

Existing data has been used to determine the dependence of fuel properties on burner and boiler design and operating parameters. In summary, nitrogen oxides emissions are the sum of fuel NO and of thermal NO. The fuel NO and thermal NO depend on several parameters which are summarized in Table 3.

These dependences are used in the next section to explain the variation of nitrogen oxide observed when coals, burner, and boiler design and operation are changed.

RESULTS

Pennsylvania Electric Company (Penelec) is conducting a program to identify the potential of firing low-volatile coals in boilers. Measurements of NOx made during this program provided data to test the dependence of NOx on fuel and burner, and boiler parameters developed in this paper.

Measurements of NOx emissions were made on four different Penelec boilers described in Table 2. One is the opposed fired 660 MWe boiler shown in Figure 8. This boiler is equipped with 48 modified dual-register burners shown in Figure 9b. Emissions of NOx were measured on this boiler for the high-volatile (baseline) and a low-volatile coal characterized in Table 3. Measurements were made at different loads, distrbution of coal to the mills, and primary air velocities.

Emissions of NOx were made at Seward Units 12 and 14, the 30 MWe wall-fired units shown in Figure 10. These units are equpped with swirl burners shown in Figure 11. Measurements of NOx included emissions from the baseline coal at different loads and exhaust gas levels of O_2.

Emissions of NOx were also made for Seward Unit 15, a 137 MWe tangentially fired unit shown in Figure 12. Seward Unit 15 is equipped with 16 tangentially fired burners shown in Figure 9a. Emissions of NOx were made at different loads and exhaust gas O_2 levels.

Future work will measure the emissions of NOx while firing a low-volatile coal at Seward Units 12, 14, and 15.

COAL PROPERTIES

Switching to the low-volatile coal at Homer City Unit 3 initially increased NOx emissions by 25%. The change in the coal also resulted in a lower primary air velocity and overall stoichiometry. Table 3 shows that the low-volatile coal contained 1.5% nitrogen (daf) and 18.0% volatile matter (ar) compared to the baseline coal of 0.98% nitrogen (daf) and 26.3% volatile matter (ar). Correlations shown in Figure 4 and Table 2 indicate that the nitrogen oxide emissions at unstaged conditions should be higher because of the increased nitrogen in the fuel, but lower because of the reduced volatile matter in the fuel. The expression predicts the low-voltile coal to increase NOx by 80% for premixed unstaged combustion, 18% for radial diffusion combustion, and 30% for premixed optimally staged combustion. The mixing conditions at the actual flame appear to approximate those of a partially mixed (radial diffusion) flame.

PRIMARY AIR VELOCITY AND STOICHIOMETRY

Decrease in the primary air velocity increases the residence time in the flame region and reduces the level of oxygen in the primary air stream. However, the gas phase stoichiometry could be increased by 5% for the low volatile coal which, according to Figure 6 and Table 1 would increase NOx emissions by 20%. The decrease in residence time under oxidizing conditions would reduce NOx emissions by 5% according to Table 1.

Changes in the primary air velocity may also have altered the effective mixing caused by the swirl. A reduction of swirl by 5% would result in a 9% reduction of flame stoichiometry ratio and a 30% decrease in NO.

The overall observed change in NOx emissions when the primary air velocity was increased by 5% was a 10% decrease in NOx emissions. Insufficient information is available to ascertain the cause of this change. However, a simple multiplicative balance of the effects described above would result in an 8% reduction of NOx.

BIAS FIRING

Bias firing also reduced the emissions of NOx. Firing only air through the top burners on one wall and redistributing the fuel to the lower burners resulted in a 25% reduction in NOx emissions. Reducing the fuel flow to the minimum in the top row of burners on both walls and redistributing the fuel to the lower burners resulted in a 14% decrease in NOx emissions.

LEVEL OF O_2

The influence of oxygen concentration at the economizer was obtained for Homer city 3, and Seward 12, 14, and 15. Figure 13 shows that the oxygen trend measured in this study is similar to that derived from data of other studies. The data is more scattered than that presented in Figure 2. No definitive reason is known for this scatter except for the large difference in unit sizes, operation conditions, and designs of the units used in this study.

HRZBA

The influence of heat release in the burner zone area on NOx emissions was obtained for Homer City Unit 3, and Seward Units 12, 14, and 15. Figure 14 shows that the NOx emissions measured in this study follow the trend derived from data of other studies. The data measured in this study is more scattered than the data shown in Figure 3. The apparent increased scatter in the data of this study may be partially caused by the inability to normalize the data of this study for constant oxygen concentration as was done for the data in Figure 3.

CONCLUSION

This study has derived the functional dependence of NOx formation in boilers from data available in the literature. These dependences were used with good success to explain the changes in NOx emissions with changes in coal properties, boiler design, and boiler operation for the four boilers of different size and design.

DISCLAIMER

The work described in this paper was not funded by the U.S. Environmental Protection Agency and therefore the contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

REFERENCES

1. Barsin, J. A. Pulverized Coal Firing NOx Control. In: Proc. of Second NOx Control Technology Seminar. EPRI-FP-1109-SR. Electric Power Research Institute, Palo Alto, CA, 1979. p. 8-1.

2. Barsin, J. A.. Fossil Steam Generator NOx Control Update. In: Proc. of Joint Symposium on Stationary Combustion NOx Control. IERL-RTP-1087. U.S. Environmental Protection Agency, Research Triangle Park, NC, 1980. p. V-69.

3. Chen, S. L. et al., "Influence of Coal Composition on the Fate of Volatile and Char Nitrogen During Combustion," In: Proc. Nineteenth Symposium (Intl) on Combustion. The Combustion Institute, Pittsburgh, PA, 1983. p. 1271.

4. Pohl, J. H. et al. Correlation of NOx Emissions with Basic Physical and Chemical Characteristics of the Coal. In: Proc. Joint Symposium on Stationary Combustion NOx Control. EPRI CS-3182, Vol. II. Electric Power Research Institute, Palo Alto, CA, 1983. p. 36-1.

5. Pohl, J. H. Pulverized Coal Research: Needed, Desired, and Superfluous. Paper presented at Eighth International Coal and Solid Fuels Utilization Exhibition and Conference, Houston, TX. Coal Technology Committee, Pittsburgh, PA, November 10-11, 1985.

6. Schultz, W. Experimentelle Untersuchung der Bildung von Stickstoffoxiden bei der Kohlenstaubuerbrennung. Doctorarbeit, Ruhr-Universitut Bochum, West Germany, 1985. p. 218.

7. Schultz, W. and Kremer, H. Influence on Temperature of the Formation of NOx During Pulverized Coal Combustion. Paper presented at Twenty-First Symposium (Intl) on Combustion, Munich, West Germany. The Combustion Institute, Pittsburgh, PA, August 3-8, 1986.

8. Chen, S. L. et al. Bench-Scale NO Emissions Testing of World Coals: Influence of Particle Size and Temperature. In: Proc. 1982 Joint Symposium on Stationary Combustion NOx Control. EPRI CS-3182, Vol. II. Electric Power Research Institute, Palo Alto, CA, 1983. p. 35-1.

9. Folsom, B. et al. NOx Emissions Control with the Distributed Mixing Burner. In: Proc. 1982 Joint Symposium on Stationary Combustion NOx Control. EPRI CS-3182, Vol. I. Electric Power Research Institute, Palo Alto, CA, 1983. p. 10-1.

10. Leikert, K. and Michelfelder, S. Operating Experience and Field Data of a 700 MW Coal-Fired Utility Boiler with Retrofit Low-NOx Staged Mixing Burners. In: Proc. Joint Symposium on Stationary Combustion NOx Control. EPA IERL-RTP-1083, Vol. I. U.S. Environmental Protection Agency, Research Triangle Park, NC, 1980. p. 251.

11. Vatsky, J. Development and Field Operation of the Control Flow/Split-Flame Burner. In: Proc. Joint Symposium on Stationary Combustion NOx Control. EPA-600/9-81-028b, Vol II (NTIS PB81-236127). U.S. Environmental Protection Agency, Research Triangle Park, NC, 1981.

12. Lisaukas, R. A. et al. Extrapolation of Burner Peformance from Single Burner Tests to Field Operation. Paper presented at 1985 Joint Symposium on Stationary Combustion NOx Control, Boston, MA. Electric Power Research Institute, Palo Alto, CA, May 6-9, 1985.

13. McCartney, M. S. and Collette, R. J. Status of Tangential Firing Low NOx Technology. In: Proc. 1982 Joint Symposium on Stationary Combustion NOx Control. EPRI CS-3182, Vol. I. Electric Power Research Institute, Palo Alto, CA, 1983. p. 7-1.

14. Azuhata, S. et al. A Study of Gas Composition Profiles for Low NOx Pulverized Coal Combustion and Burner Scale-Up. Paper presented at 21st International Symposium on Combution, Munich, West Germany. The Combustion Institute, Pittsburgh, PA, August 11-15, 1986.

15. Hendricks, R. V. et al. Wall-Fired LIMB Demonstration Design for Ohio Edison Edgewater Unit 4. Paper presented at 1986 EPRI/EPA Joint Symposium on Dry SO_2 and Simultaneous SOx/NOx Control Technologies, Raleigh, NC. Electric Power Research Institute, Palo Alto, CA, June 2-6, 1986.

16. Okigami, N. Three-Stage Pulverized Coal Combustion System for In-Furnace NOx. Paper presented at the 1985 Joint Symposium on Stationary Combustion NOx Control, Boston, MA. Electric Power Research Institute, Palo Alto, CA, May 6-9, 1986.

17. Fujiyama, K. Status of EPDC's NOx Control Technology. Paper presented at 1985 Joint Symposium on Stationary Combustion NOx Control, Boston MA. Electric Power Research Institute, Palo Alto, CA, May 6-9, 1985.

18. Heap, M. P. et al. Burner Design Principles for Minimum NOx Emissions. In: Proc. Coal Combustion Seminar, EPA-650/2-73-021 (NTIS PB 224-210). U.S. Environmental Protection Agency, Research Triangle Park, NC, 1973. p. 141.

19. Pershing, D. W. et al. Relationship of Burner Design to the Control of NOx Emissions through Combustion Modifications. EPA-650/2-73-021 (NTIS PB 224-210). U.S. Environmental Protection Agency, Research Triangle Park, NC, 1973. p. 87.

20. Thompson, R. E. Nitric Oxide Controls for Coal-Fired Utility boilers from an Applications Viewpoint. In: Proc. Second NOx Control Technology Seminar. EPRI FP-1109-SR. Electric Power Research Institute, Palo Alto, CA, 1979. p. 9-1.

21. Bartok, W. et al. Systems Study of Nitrogen Oxide Control Methods for Stationary Sources. Esso Research and Engineering Company Final Report GR-2-NOS-69 (NTIS PB 192 789). National Air Pollution Control Associates Contract No. PH 22-68-55, Cincinnati, OH, 1969.

22. Vatsky, J. Experience in Reducing NOx Emission in Operating Steam Generators. In: Proc. Second NOx Control Technology Seminar. EPRI FP-1109-SR, Electric Power Research Institute, Palo Alto, CA, 1979. p. 7-1.

23. Quan, V. et al. Analytic Scaling of Flow Field and Nitric Oxide in Combustors. Combus.Sci.Tech. 9:202, 1972.

24. Payne, R. et al. Studies of the Pollutant Emission Characteristics of a Number of Oil-Fired Industrial Burners and the Relationship to Firing Conditions. IFRF Doc. Nr. F3T/2/6, International Flame Research Foundation, IJmuiden, Netherlands, 1980.

25. Abele, A. R. et al. Evaluation of Non-U.S. Coals Emission Performance with the Distributed Mixing Burner. EPA-68-02-3947, U.S. Environmental Protection Agency, Research Triangle Park, NC, 1985.

26. Smoot, L. D. NOx Prediction for Practical Pulverized Coal Reactors. Paper presented at 1985 Joint Symposium on Stationary Combustion NOx Control, Boston, MA. Electric Power Research Institute, Palo Alto, CA, May 6-9, 1985.

27. LaRue, A. D. and Rodgers, L. W. Development of Low-NOx Cell Burners for Retrofit Applications. Paper presented at 1985 Joint Symposium on Stationary Combustion NOx Control, Boston, MA. Electric Power Research Institute, Palo Alto, CA, May 6-9, 1985.

28. Pershing, D. W. and Wendt, J.O.L. Pulverized Coal Combustion: The Influence of Flame Temperature and Coal Composition on Thermal and Fuel NOx. In: Proc. 16th Symposium (Intl) on Combustion. The Combustion Institute, Pittsburgh, PA, 1977. p. 389.

29. Sarofim, A. F. and Pohl, J. H. Kinetics of Nitric Oxide Formation in Premixed Laminar Flames. In: Proc. 14th Symposium (Intl) on Combustion. The Combustion Institute, Pittsburgh, PA, 1973. p. 739.

30. Pohl J. H. and Sarofim, A. F. Devolatilization and Oxidation of Coal Nitrogen. In: Proc. 16th Symposium (Intl) on Combustion. The Combustion Institute, Pittsburgh, PA, 1977. p. 491.

31. Song, Y. H. et al. Nitric Oxide Formation During Pulverized Coal Combustion. Combus.Sci.Tech. 28:31, 1982.

32. Johnson, S. A. et al. The Primary Combustion Furnace System--An Advanced Low-NOx Concept for Pulverized Coal Combustion. In: Proc. Second NOx Control Technology Seminar. EPRI FP-1109-SR, Electric Power Research Institute, Palo Alto, CA, 1979. p. 13-1.

33. Payne, R. et al. Aspects of NOx Formation and Reduction in Coal-Fired Combustion Systems. IFRF Doc. Nr . F37/a/10, International Flame Research Foundation, IJmuiden, Netherlands, 1981.

34. Beer, J. M. and Chigier, N. A. Combustion Aerodynamics. Halstead Press, New York, NY, 1972.

35. Payne, R.. Private communication. Energy and Environmental Research Corp., Irvine, CA, 1981.

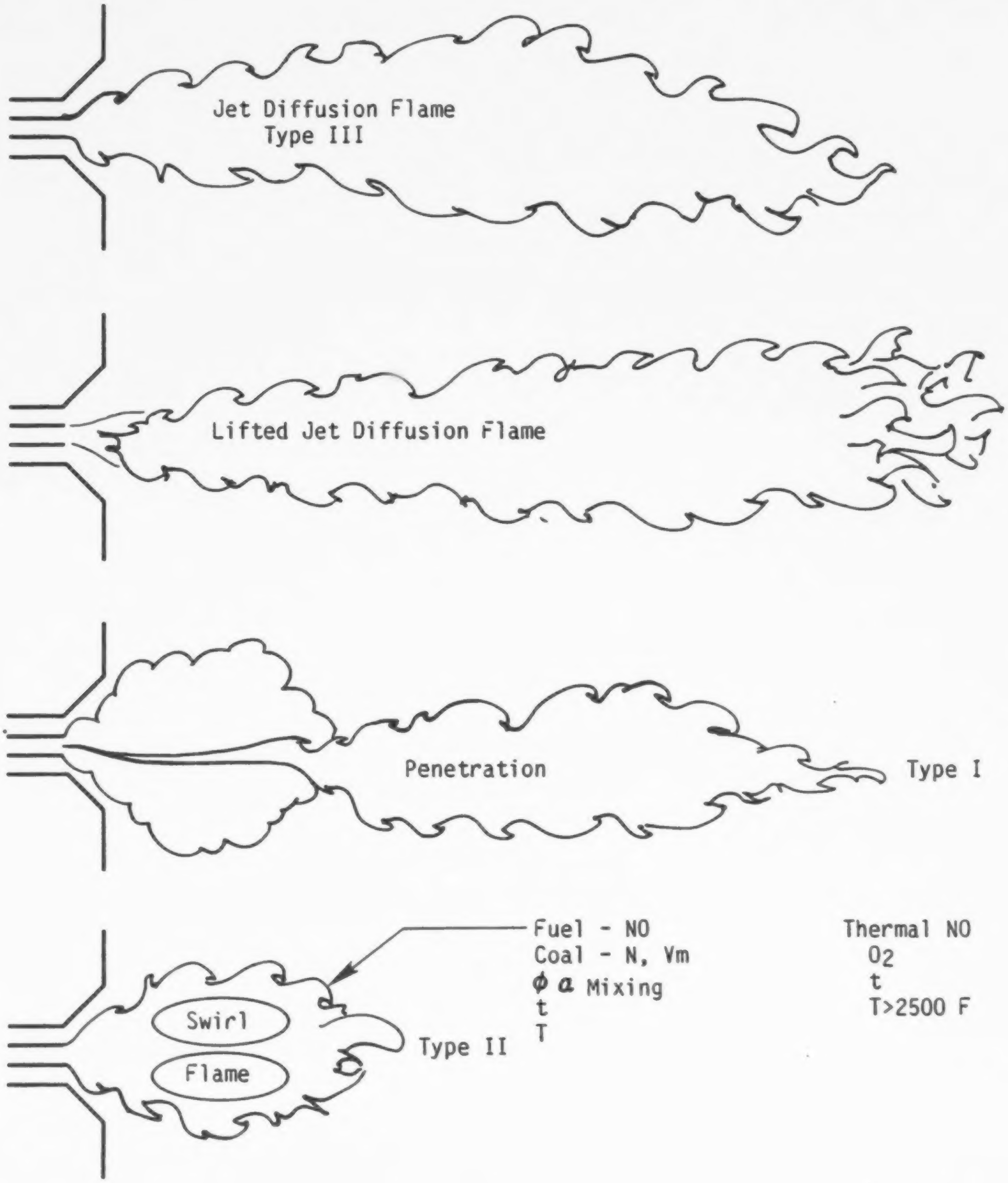

Jet Diffusion Flame
Type III
Lifted Jet Diffusion Flame
Penetration
Type I
Swirl
Flame
Type II
Fuel - NO
Coal - N, Vm
ϕ α Mixing
t
T
Thermal NO
O_2
t
T>2500 F

Figure 1. Flame characteristics and mechanisms of NOx formation.

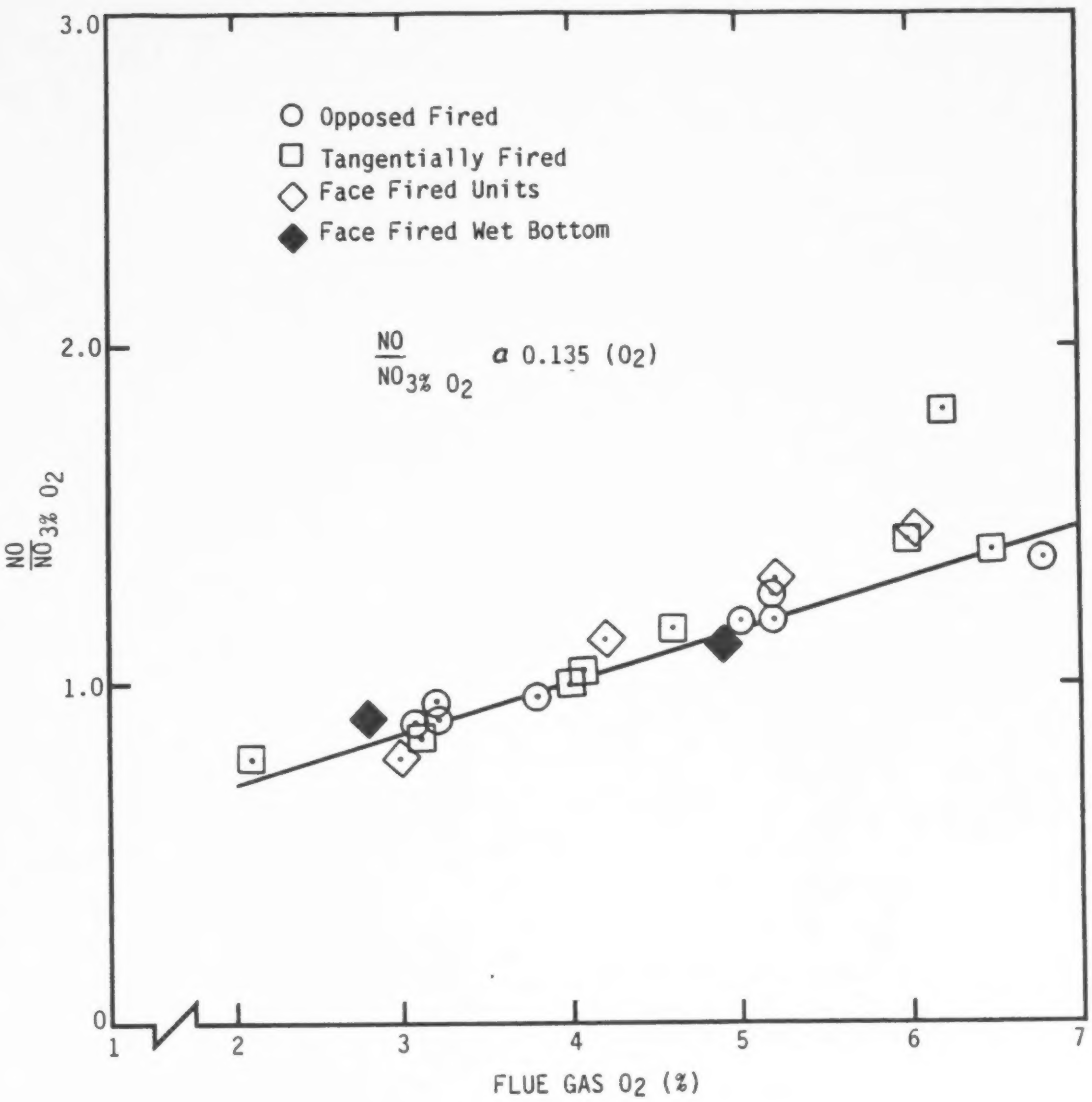


Figure 2. Influence of O_2 on NOx emission.

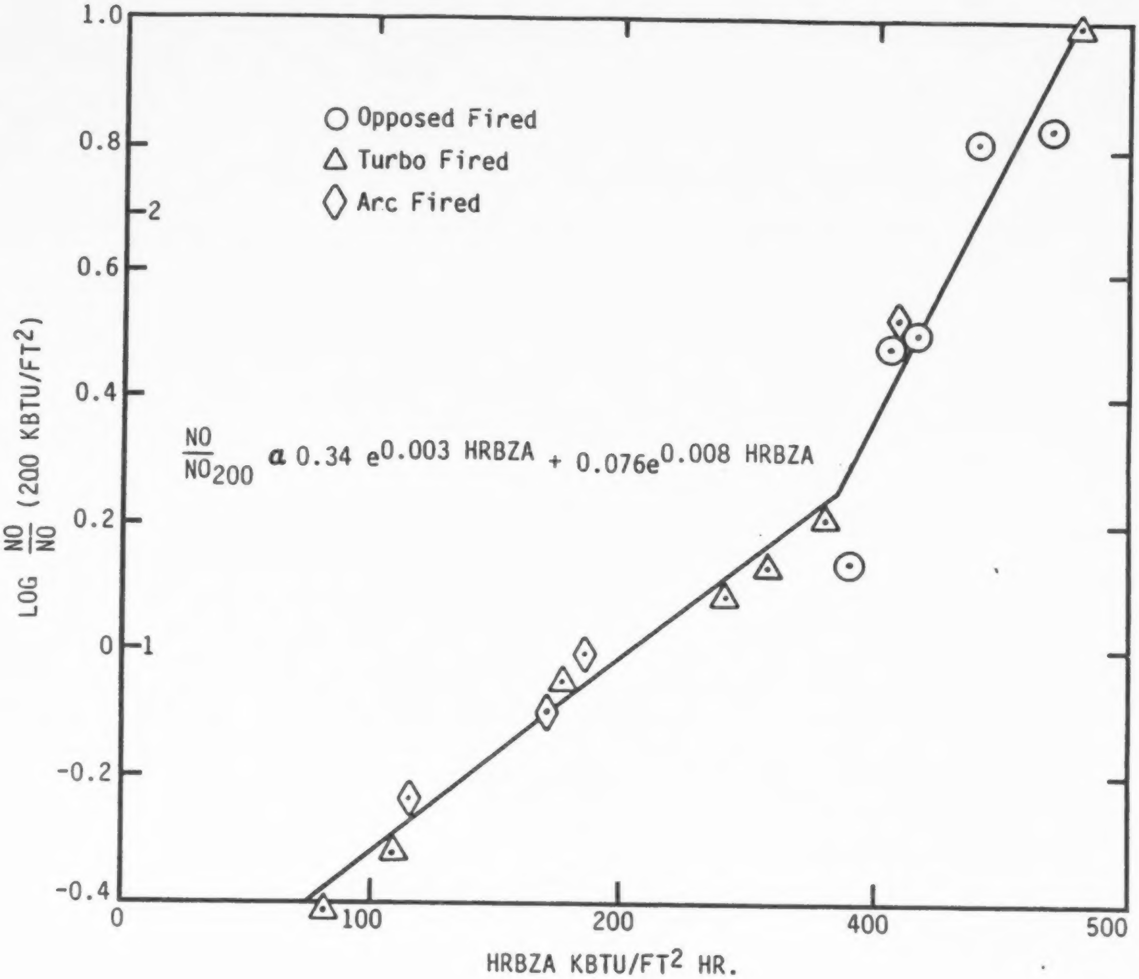
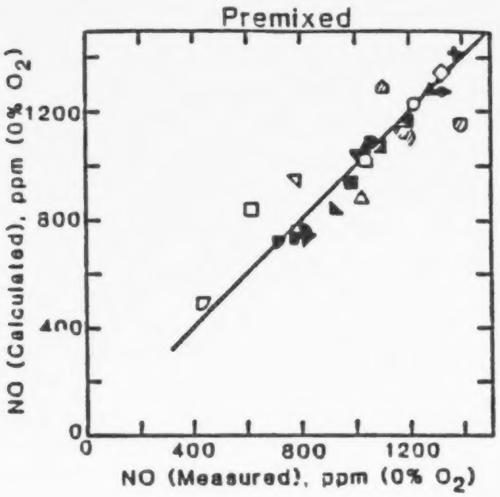


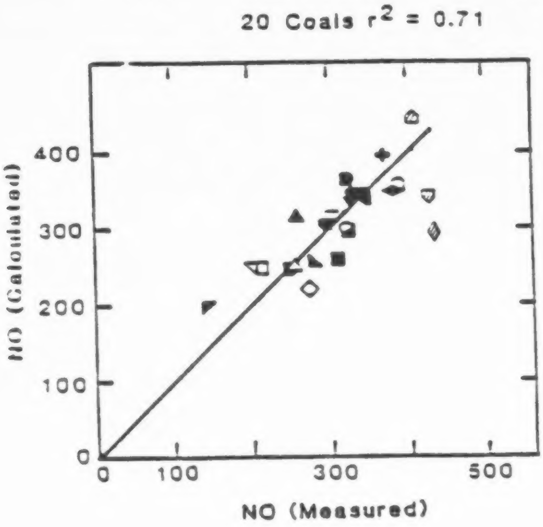
Figure 3. Influence of burner zone heat release on NOx emissions.

$$NO = 385 + 1280\left(\frac{No}{1.5}\right) + 180\left(\frac{VM}{40}\right)\left(\frac{NOeq}{3200}\right) - 840\left(\frac{FC}{60}\right)\left(\frac{NOeq}{3200}\right)$$



a. Premixed Flame, ϕ = 1.2

$$NO = 150 + 80\left(\frac{No}{1.5}\right) - 30\left(\frac{VM}{40}\right)\left(\frac{NOeq}{3200}\right) + 100\left(\frac{FC}{60}\right)\left(\frac{NOeq}{3200}\right)$$



b. Optimally Staged Premixed Flame, ϕ = 1.2

Figure 4. Correlation of coal properties with NOx emission at fixed flame conditions (4, 5).

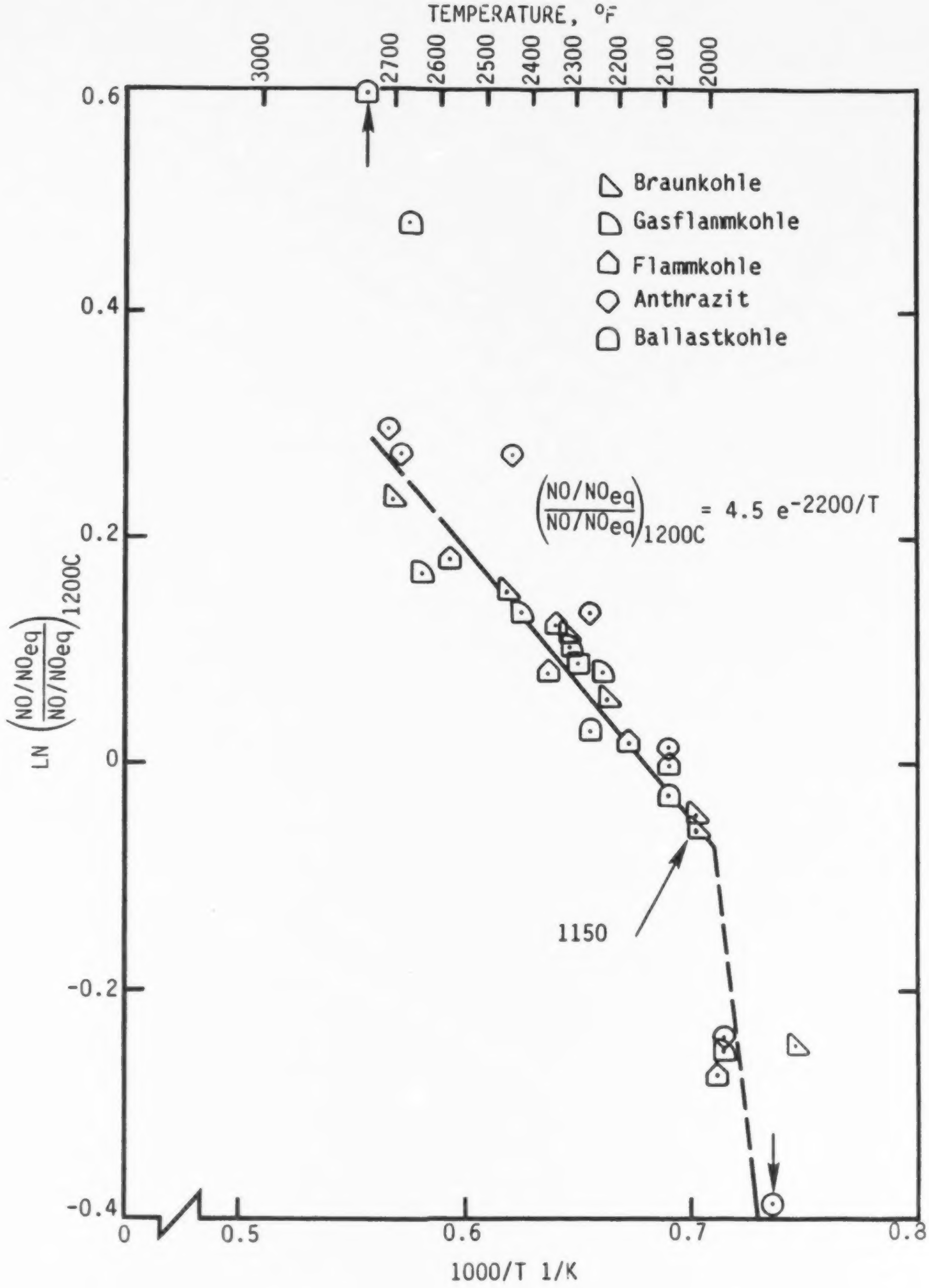


Figure 5. Influence of temperature on fuel nitrogen conversion.

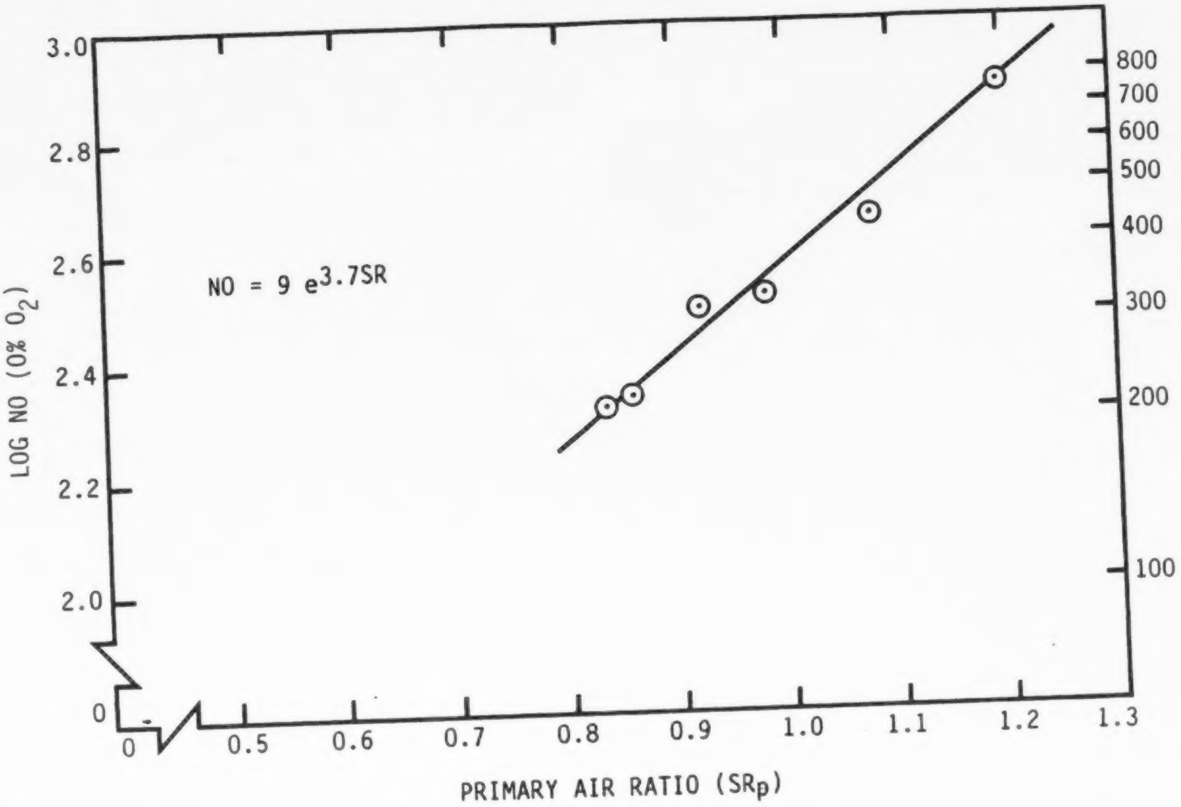
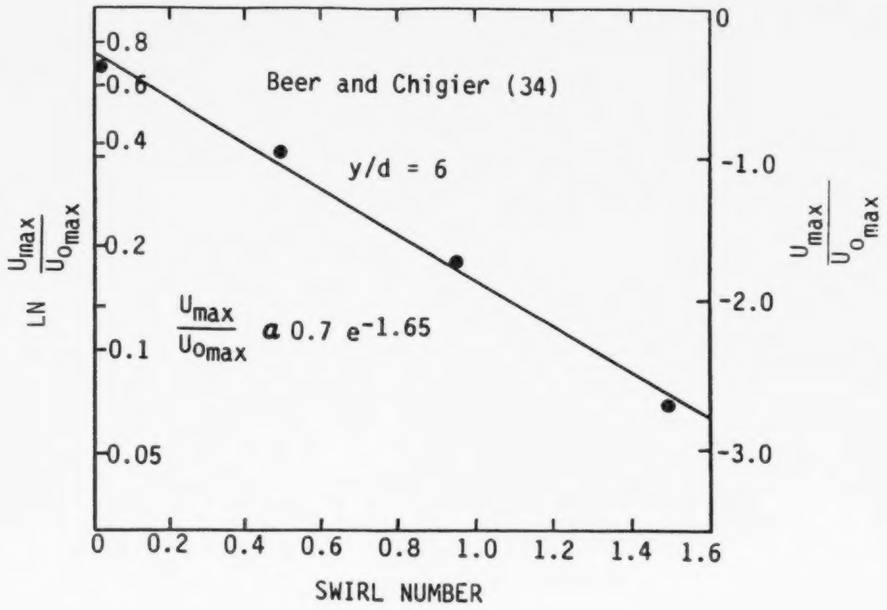
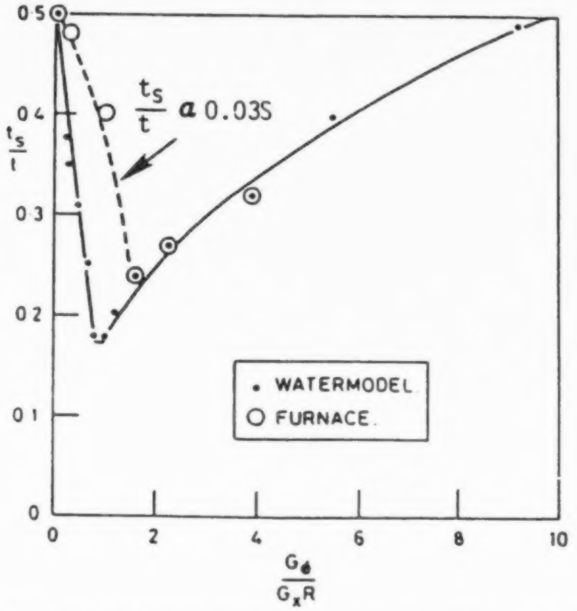


Figure 6. Influence of primary stoichiometry on NOx emissions.



a. Influence of Swirl on Entrainment.



b. Residence Time in Stirred Section as a Fraction of Total Residence and Swirl Number.

Figure 7. Influence of swirl (34).

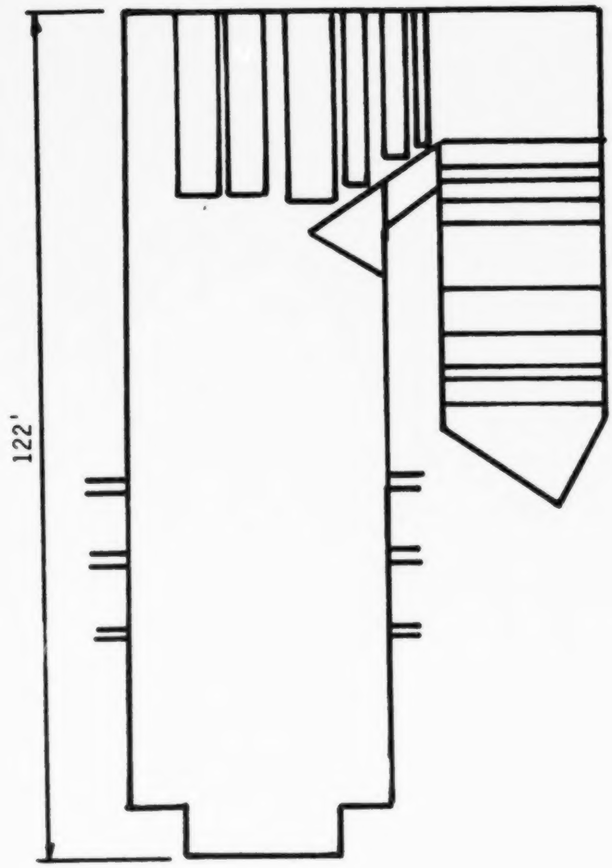
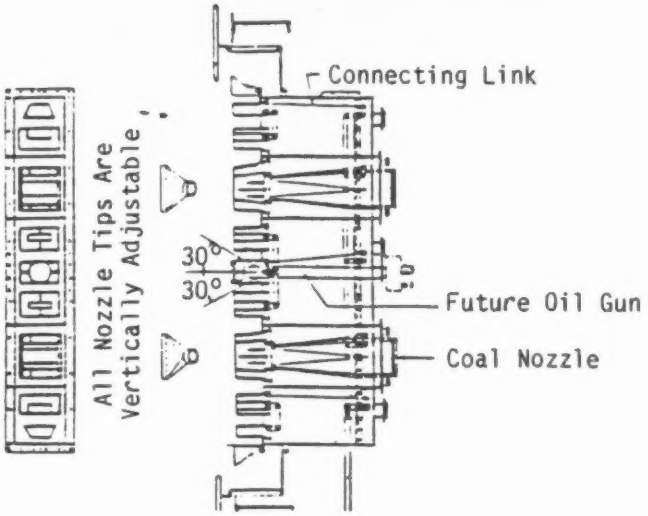
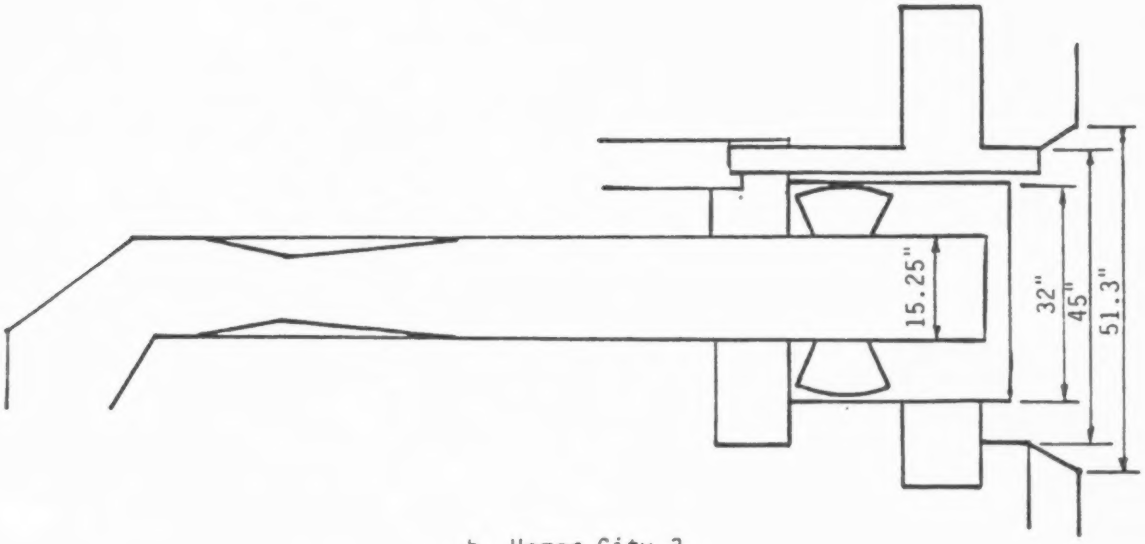


Figure 8. 660 MWe unit, Homer City 3.


Connecting Link
All Nozzle Tips Are Vertically Adjustable
30°
30°
Future Oil Gun
Coal Nozzle

a. Seward 15


15.25"
32"
45"
51.3"

b. Homer City 3

Figure 9. Burners.

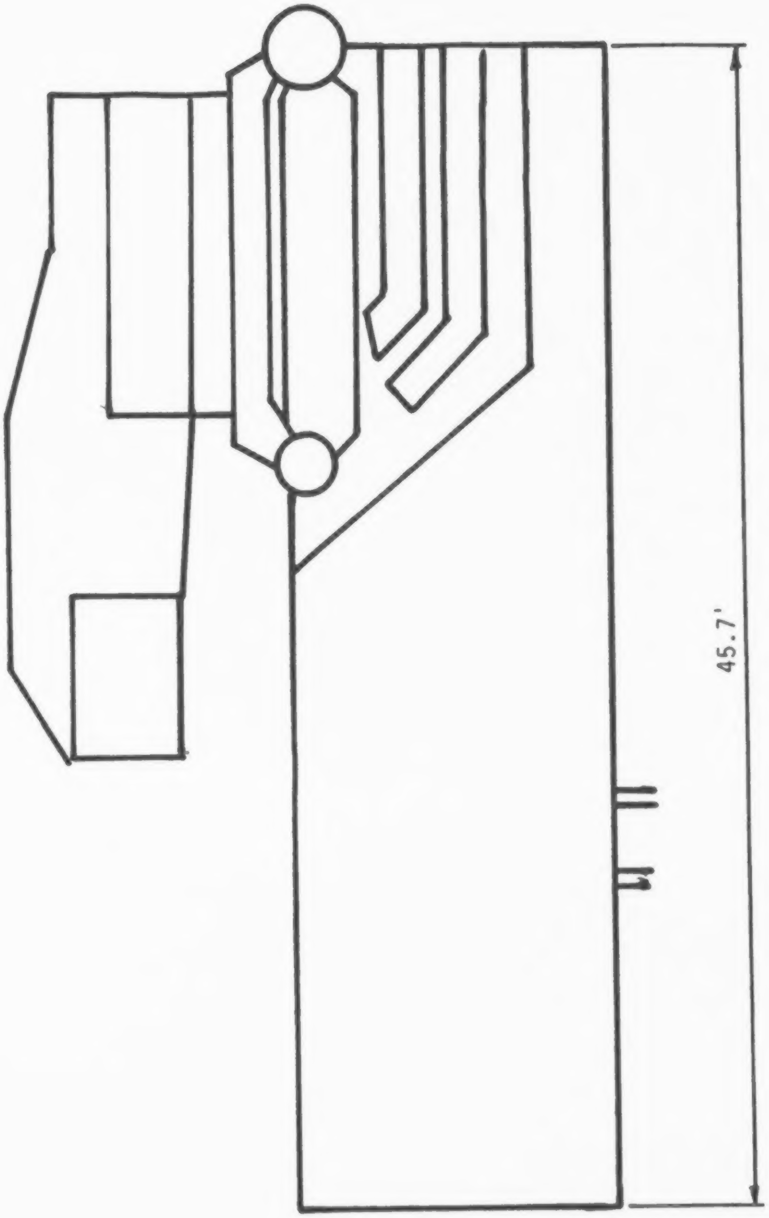


Figure 10. 30 MWe unit, Seward 12 and 14.

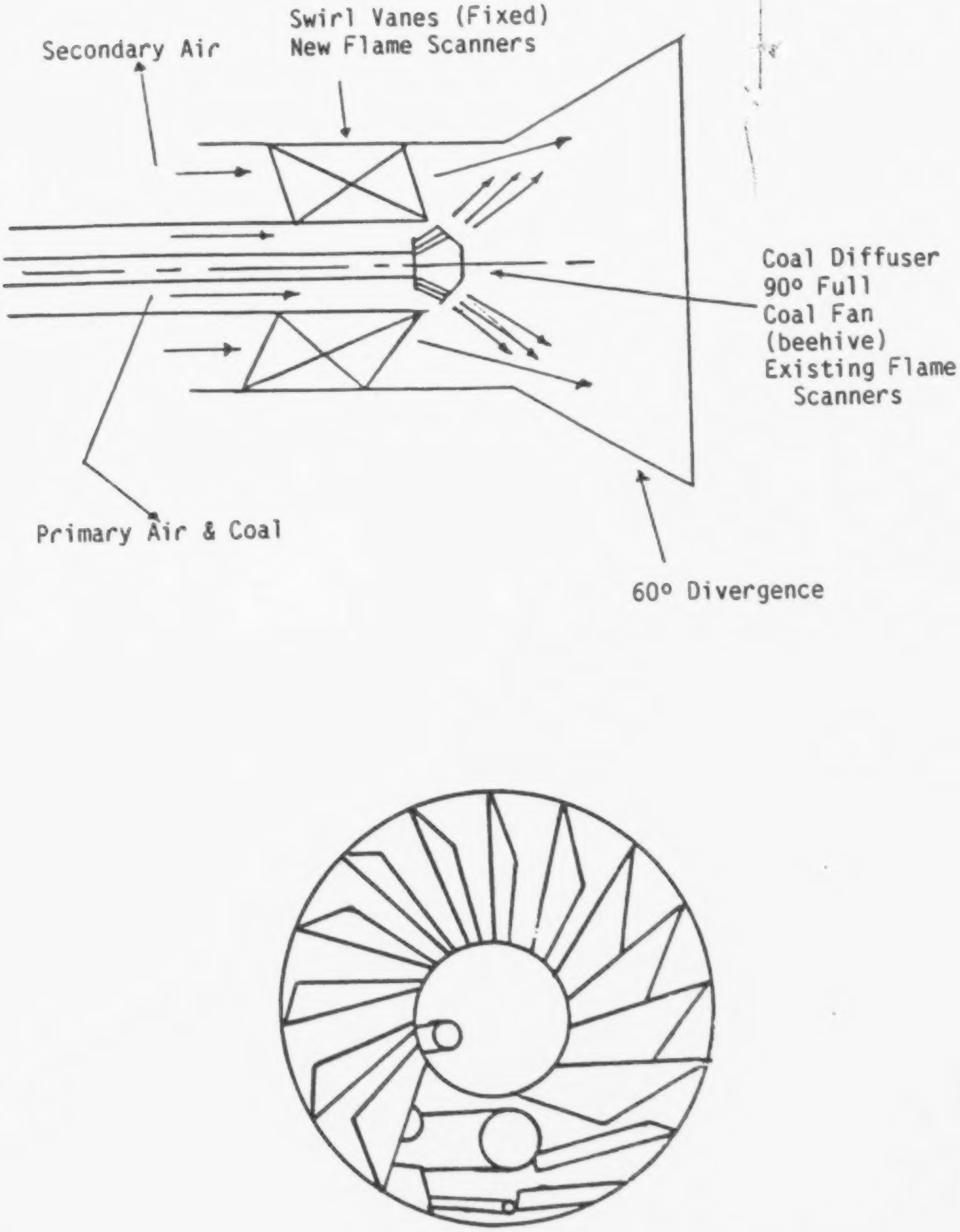

Secondary Air
Swirl Vanes (Fixed)
New Flame Scanners
Coal Diffuser
90° Full
Coal Fan
(beehive)
Existing Flame
Scanners
Primary Air & Coal
60° Divergence

Figure 11. Burner, Seward 12 and 14.

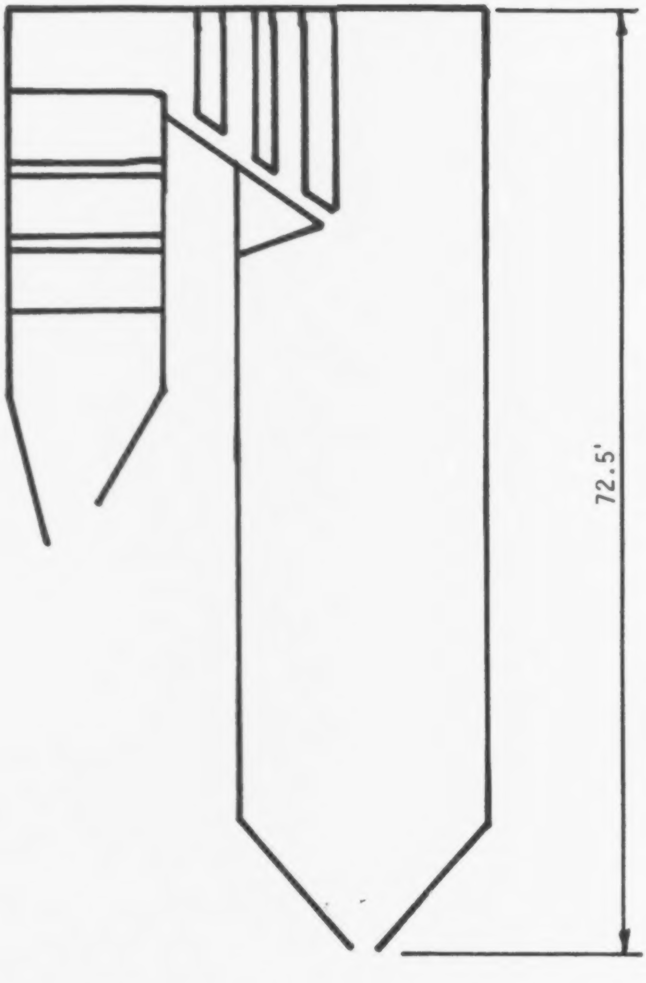


Figure 12. 137 MWe unit, Seward 15.

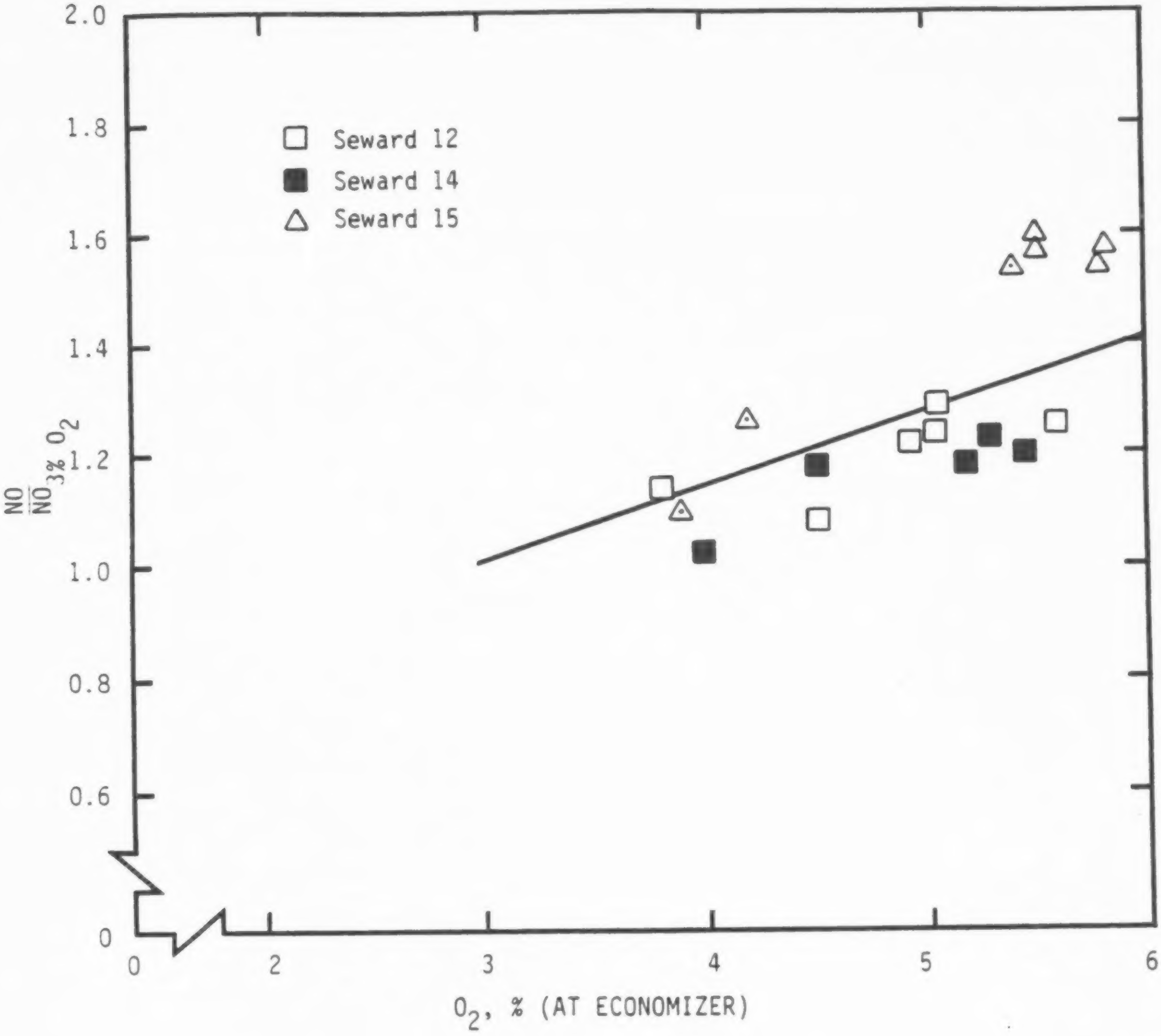


Figure 13. Influence of oxygen concentration on NOx emissions.

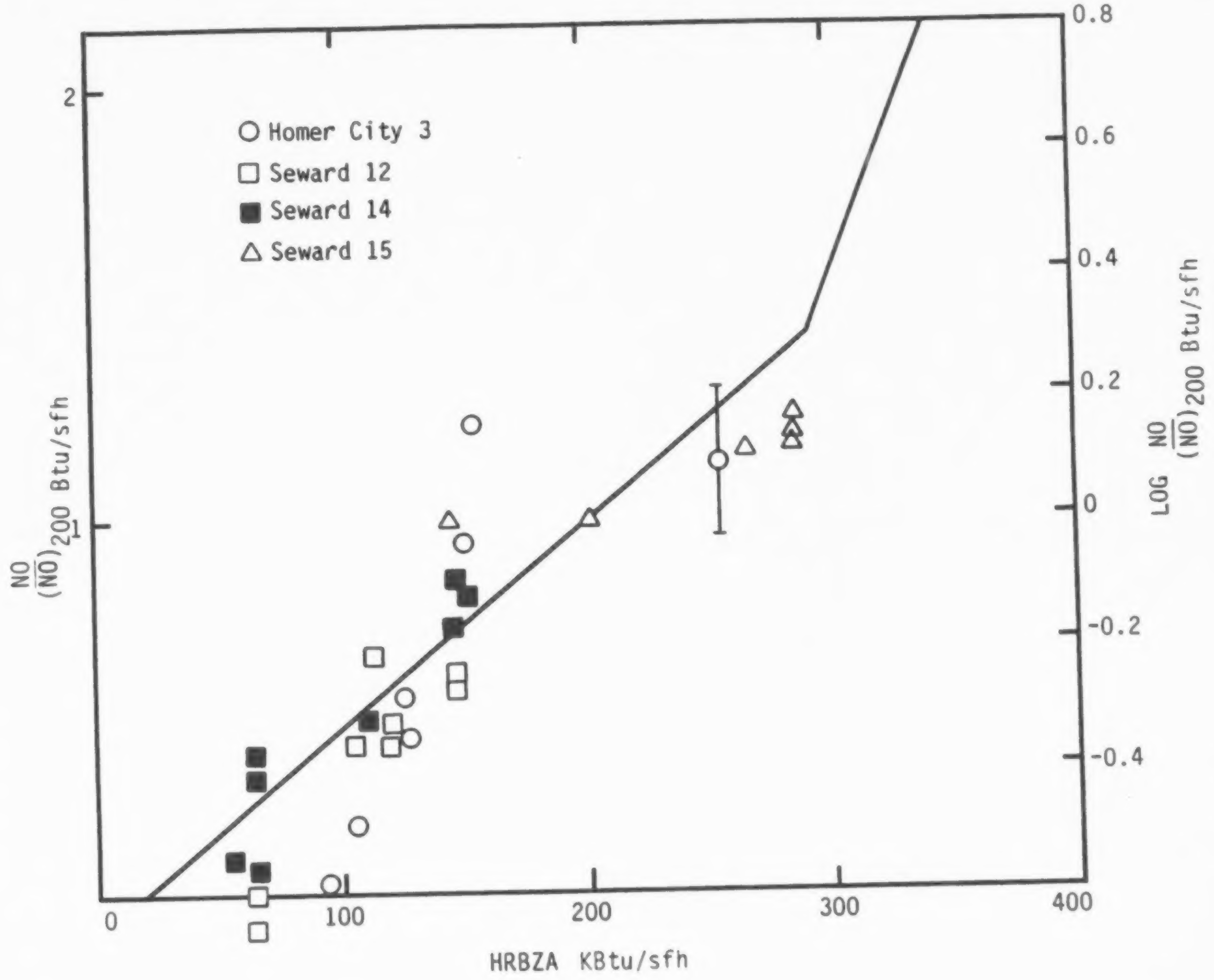


Figure 14. Influence of HRBZA on NOx emissions.

TABLE 1. DEPENDENCE OF NOx EMISSIONS ON FUEL, BURNER DESIGN, AND OPERATING PARAMETERS

	FUEL NOx	
Primary Stoichiometry	$NO \sim 9\ e^{3.7SR}$	
Primary Velocity	$NO \sim V/d^{2.5}$	
Coal	$NO \sim AN_0 + BVM\ (NO_{eq})$ $NO \sim CN_0 - DVM\ (NO_{eq})$	Lean flame zone Rich flame zone
Swirl (Entrainment)	$SR \sim 0.7\ e^{-165}$	Swirl burners
Swirl (Residence Time)	$NO \sim 1/0.3S$	Swirl burners
Residence Time	$NO \sim 1/HRZBA$	Tangential firing
Temperature	$NO/NO_{eq} \sim e^{-E/HRBZA}$	2100 - 2700 °F
	THERMAL NOx	
Oxygen	$NO \sim 0.135\ (O_2)$	
Temperature	$NO \sim 0.34\ e^{-0.003HRBZA} + 0.076\ e^{0.008HRBZA}$	

TABLE 2. BOILER AND BURNER CHARACTERISTICS

Plant	Homer City	Seward		Seward
Unit	3	12	14	15
Manufacturer	Babcock & Wilcox	Babcock & Wilcox		Combustion Engg
Capacity, MW	600	30		137
Burner Arrangement	Opposed	Wall fired		Tangential
Burner	Mod. Dual Register	Coal impeller		Tilting Tangen.
No. of Burners	48	6		16
Coal Nozzle, ft.	1.25	0.83		1.42 x 1.42
Inner Air, ft.	2.67	2.33		1.42 x 0.67
Outer Air, ft.	3.75	4.33		---
Burner Spacing, ft.	10.5 x 15.0	6.6 x 6.2		4.9 corners
Pressure Drop, in.W.G.	2.5	0.8-3.5	1.0-4.8	2.0-3.5
MBtu/hr	5759	367		1326
Dimensions, WxDxH, ft.	51.0x73.0x122.0	18.0x24.0x72.5		22.0x27.0x110.0
Volume, cu.ft.	390,603	16,502		61,702
Plan Area, sq.ft.	3723	432		528
EPRS, sq.ft.	48,534	4958		9982
Burner Zone Area, sq.ft.	22,326	2460		4770
Btu/cfh	14,178	22,240		21,490
FPHRR, MBtu/sfh	1.49	0.85		2.5
HREPRS	119	74		133
HRBZA, KBtu/sfh	248	149		278
Coal Flow, lb/hr	432,000	30,800		112,000
Primary Air Flow, lb/hr	821,300	61,600		168,000
Second. Air Flow, lb/hr	3,873,400	218,400		952,000
Air Temperature, °F		435-480	460-490	505-518
FGET		2000	2200	2100-2200
NO at 0% O_2	540-770	610-680	700-735	665-690

TABLE 3. COAL CHARACTERISTICS

	Baseline Coal Homer City 3	Low Vol Coal Homer City 3	Baseline Coal Seward 12, 14, 15
H_2O (ar)	2.5	5.7	7.5
Vm (ar)	26.3	18.0	18.6
Vm (daf)	30.6	20.5	24.0
Ash (ar)	11.5	6.7	15.0
S (ar)	1.0	0.77	1.41
HHV (ar), Btu/lb	13,332	13,741	11,922
LHV (ar), Btu/lb	12,820	13,281	11,510
C (daf)	87.3	88.8	89.5
H (daf)	5.3	5.0	4.7
N (daf)	0.98	1.5	1.3
S (daf)	1.17	0.88	1.8
O (daf)	5.25	3.8	2.7
NO, ppm (dry, at 0% O_2)	1775	2625	2312

Appendix A.

1987 Joint Symposium on Stationary Combustion NOx Control

03/23/87-03/26/87

New Orleans, LA

List of Attendees

Duane Abbott
Project Manager
Stauffer Chemical Company
Sulfuric Products Division
2950 N. Loop West, Suite 700
Houston, TX 77092
713/688-9311

Rui F. Afonso
Group Manager
Dynatech Scientific
99 Erie Street
Cambridge, MA 02139
617/868-8050

William R. Alcorn
Mgr., Research & Development
Camet
12000 Winrock Road
Hiram, OH 44234
216/569-3245

Sy A. Ali
Section Chief E.C. & A.F. Tech.
General Motors
Allison Gas Turbine Division
P.O. Box 420, W16
Indianapolis, IN 46206-0420
317/242-6864

Leonard C. Angello
Project Manager
Electric Power Research Institute
P.O. Box 10412
Palo Alto, CA 94303
415/855-2873

Mamoru Araoka
Senior Engineer
Mitsubishi Heavy Industries
Shin-Tamachi Building
34-6, Shiba 5-chome
Minato-ku, Tokyo 108 JAPAN
81/3 455-5711

Al Arnott
N/A
Ontario Hydro
700 University Avenue
Toronto, Canada M5G 1X6
416/592-5931

Aysel T. Atimtay
Associate Professor
Tulane University
Dept. of Chemical Engineering
New Orleans, LA 70118
504/865-5777

Richard Ayres
Senior Attorney
Natural Resources Defense Council
1350 New York Avenue, N.W.
Washington, DC 20005
202/783-7800

Colin Bailey
Principal Combustion Engineer
Kongsberg Dresser Power
3651 Pegasus, Suite 111
Bakersfield, CA 93308
805/392-8400

Ronald F. Balingit
Mechanical Engineer
Los Angeles Dept. of Water & Power
111 N. Hope Street
Los Angeles, CA 90012
213/481-5382

Lawrence J. Barna
Senior Engineer-Mechanical
Northern Indiana Public Service Co.
5265 Hohman Avenue
Hammond, IN 46320
219/853-6956

Anthony Barnbrough
Head, Major Combustion Sources
Environment Canada
351 Boulevard St. Joseph
Hull, Quebec
CANADA K1A 0E7
819/953-1124

Joseph A. Barsin
Manager, Industrial Projects
Babcock & Wilcox
20 S. Van Buren Avenue
Barberton, OH 44203
216/860-1025

William Bartok
Senior Vice President
Energy & Envrnmntl. Research Corp.
1090 King George Post Rd., #104
Edison, NJ 08837
201/225-1300

Melvin D. Bassett
Generating Plant Specialist
Southern Company Services
P.O. Box 2625
Birmingham, AL 35202
205/877-7662

Laurie G. Batchelor
Engineer, Air Compliance
Alabama Power Company
P.O. Box 2641
Birmingham, AL 35291-0830
205/250-4407

Nick Bayard
President
ETEC
2091 Business Center Drive
Suite 100
Irvine, CA 92715
714/833-2522

Bernard Becker
Engineer
Kraftwerk Union AG
Postfach 1420
D-4330 Muelheim
FEDERAL REPUBLIC OF GERMANY
N/A

Roderick Beittel
Head, Combustion Research Section
Southern Research Institute
P.O. Box 55305
Birmingham, AL 35255
205/323-6592

Bruno Bellomo
N/A
Ente Nazionale per L'Energia Elec.
00918 Roma
Via G. B. Martini, 3
ITALY
06/8509 2745

Angelo Benanti
N/A
Ente Nazionale per L'Energia Elec.
00918 Roma
Via G. B. Martini, 3
ITALY
06/8509 2745

Joe D. Bentley
Engineer, Air Quality
Lower Colorado River Authority
P.O. Box 220
Austin, TX 78767
512/473-3200

Mogens Berg
N/A
Elkraft Power Company
5, Lautruphoej
2750 Ballerup
DENMARK
+45/2 66 00 22

Greg W. Betenson
Chemical Engineer
Utah Power Company
419 Wakara Way, Suite 101
Salt Lake City, UT 84108
801/584-1911

Gary L. Bisonett
Senior Steam Generation Engineer
Pacific Gas & Electric Company
77 Beale Street, Room 3035
San Francisco, CA 94106
415/972-6950

N. J. Blokker
President
Amsterdam Power Company
c/o Royal Schelde, P.O. Box 16
4380 AA Vlissingen
THE NETHERLANDS
31/1184-82414

Julian Blomley
Environmental Anaylst
MSU System Services
P.O. Box 61000
New Orleans, LA 70161
504/569-4641

Richard D. Boardman
Research Assistant
Brigham Young University
Combustion Laboratory
Provo, UT 84604
801/378-2076

J. D. Bornemann
Manager, Fuel Firing Systems
Royal Schelde
P.O. Box 16
4380 AA Vlissingen
THE NETHERLANDS
31/1104-02580

Steven Bortz
Senior Scientist
KVB
18006 Skypark Boulevard
Irvine, CA 92714
714/250-6325

David J. Bott
Development Assistant
W. R. Grace & Company
7379 Route 32
Columbia, MD 21044
301/531-4124

Kerry W. Bowers
Senior Research Engineer
Southern Company Services
P.O. Box 2625
Birmingham, AL 35202
205/870-6825

Chester M. Bowling
Senior Process Engineer
ARCO Coal Company
555 17th Street, DAT-2106
Denver, CO 80202
303/293-7732

Edwin J. Brailey, Jr.
Consulting Engineer
New England Power Service Company
25 Research Drive
Westborough, MA 01582
617/366-9011

Barbara A. Brandon
Senior Engineer
San Diego Gas & Electric Company
P.O. Box 1831
San Diego, CA 92112
619/235-7765

Atly Brasher
Program Mgr., Technical Services
Department of Environmental Quality
P.O. Box 44096
Baton Rouge, LA 70804
504/342-9029

Bernard P. Breen
President
Energy Systems Associates
1840 Gateway Three
Pittsburgh, PA 15222-1004
412/392-2380

Paul Breeze
Deputy Editor
Modern Power Systems
33-35 Bowling Green Lane
London, Eciroda
ENGLAND
44/1 837 1212 X215

Gifford R. Broderick
Vice President, Engineering
Fuel Tech
61 Taylor Reed Place
Stamford, CT 06906
203/359-1320

William J. Brooks
Senior Engineer
Central Electricity Gen. Board
Barnett Way
Barnwood, Glouster GL4 7RS
UNITED KINGDOM
0452/652306

Robert Bruck
Associate Professor
North Carolina State University
Department of Plant Pathology
P.O. Box 7616
Raleigh, NC 27695
919/737-2086

C. P. Brundrett
Technical Director
NOXERAM
Senefelderstrasse 15
D-5060 Bergisch Gladbach 2
Bundesrepublik, WEST GERMANY
011/49 02202 1203 30

Eugene A. Burns
Division Vice President
S-Cubed
P.O. Box 1620
La Jolla, CA 92038
619/453-0060

Kenneth R. Burns
Sales Manager
Engelhard Corporation
2655 U.S. Route 22
Union, NJ 07083
201/964-2763

John W. Byrne
Senior Research Chemist
Engelhard Corporation
Menlo Park
Edison, NJ 08818
201/321-5153

Gene Capriotti
Vice President, Sales
Fuel Tech
61 Taylor Reed Place
Stamford, CT 06906
203/359-1320

Robert C. Carr
Consultant
Electric Power Technologies
P.O. Box 307
Menlo Park, CA 94026
415/322-0828

L. D. Carter
N/A
U.S. Department of Energy
Office of Fossil Energy (FE-13)
Washington, DC 20585
202/586-9680

Charles S. Chang
Asst. Supervisor, Air Quality
Los Angeles Dept. of Water & Power
111 N. Hope Street
Los Angeles, CA 90051
213/481-3235

Weiyin Chen
Senior Research Engineer
Gulf South Research Institute
P.O. Box 26518
New Orleans, LA 70186
504/283-4223

Girish Chitnis
Development Associate
Johnson Matthey Company
456 Devon Park Drive
Wayne, PA 19087
215/341-8280

Roger C. Christman
Asst. Mgr., Research & Engr. Div.
KVB
18006 Skypark Boulevard
Irvine, CA 92714
714/250-6225

Woo C. Chung
Mechanical Engineering Associate
Los Angeles Dept. of Water & Power
111 N. Hope Street, Room 604
Los Angeles, CA 90012
213/481-4726

J. E. Cichanowicz
Project Manager
Electric Power Research Institute
P.O. Box 10412
3412 Hillview Avenue
Palo Alto, CA 94304
415/855-2379

John Clark
Plant Manager
St. Johns River Power Park
P.O. Box 26888
Jacksonville, FL 32218
904/751-7720

Matthew J. Clark
Development Engineer
Babcock & Wilcox
Research & Development Division
20 S. Van Buren Avenue
Barberton, OH 44203
216/860-2667

Eric Clatworthy
HQ Director
British Gas PLC
Rivermill House
152 Grosvenor Road
London SW 1V3JL, ENGLAND
01/821 1444 X2292

Kevin W. Cleary
Air Resources Engineer
Air Resources Board
1102 Q Street
Sacramento, CA 95814
916/322-8269

Mitchell B. Cohen
Supervisor
Combustion Engineering
1000 Prospect Hill Road
Windsor, CT 06095
203/285-2482

Jerry L. Cooper
Manager, Process Engineering
Combustion Power Company
1020 Marsh Road
Menlo Park, CA 94025
415/324-4744

James Courville
State Engineer
Department of Environmental Quality
P.O. Box 44096
Baton Rouge, LA 70820
504/342-1206

David A. Cowdrick
Senior Engineer
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601
813/228-41111 X46224

William R. Cress
Manager, Engineering Studies
Allegheny Power Service Corporation
800 Cabin Hill Drive
Greensburg, PA 15601
412/838-6721

John M. Croom
President
Quantitative Applications
3898 West Wood Path
Stone Mountain, GA 30083
404/294-6773

Kenneth E. Cross
Department Manager
Martin Marietta Energy Systems
P.O. Box P, K-1001, MS 172
Oak Ridge, TN 37831
615/574-8122

Mariana Cunningham
Design Mechanical Engineer
Los Angeles Dept. of Water & Power
111 N. Hope Street, Room 657
Los Angeles, CA 90012
213/481-7734

Stuart M. Dalton
Program Manager
Electric Power Research Institute
3412 Hillview Avenue
P.O. Box 10412
Palo Alto, CA 94034
415/855-2467

James Damon
Sr. Power Engineer
United Engineers & Constructors
Stearns Roger Division
4500 Cherry Creek Drive
Denver, CO 80217
303/692-2458

Berkley Davis
Mgr., Combustion Aerothermal Design
General Electric Company
Turbine Business Operation
Bldg. 53-322, 1 River Road
Schenectady, NY 12345
518/385-9677

Jan K. De Klerk
Engineer
Stork Boilers
P.O. Box 20, 7550 GB
Hengelo
THE NETHERLANDS
074/454321

Stefan Dersand
Project Engineer
Stockholm Energy
Stockholm Box 4454
Stockholm
SWEDEN
8-380100

Marshall Dick
Senior Engineer
U.S. EPA
401 M Street
Washington, DC 20460
202/382-5747

Roger D. Dodds
N/A
Wisconsin Electric Power Company
P.O. Box 2046
Milwaukee, WI 53201
414/221-2174

Dennis Drehmel
Chief, Technical Dev. Branch
U.S. EPA
MD-4
Research Triangle Park, NC 27711
919/541-7505

George C. Dusatko
Manager, Eastern Region
Energy Systems Associates
1840 Gateway Three
Pittsburgh, PA 15222-1004
412/392-2372

Owen W. Dykema
President
Dykema Engineering
5850 Canoga Avenue
Woodland Hills, CA 91367
818/712-0070

Sherman Eaton
Manager, Engineering Standards
Coen Company
1510 Rollins Road
Burlingame, CA 94010
415/697-0440

Michael L. Eaves
Research Projects Coordinator
Southern California Gas Company
810 S. Flower Street
Los Angeles, CA 90017
213/689-3136

James A. Eddinger
Environmental Engineer
U.S. EPA
MD-13
Research Triangle Park, NC 27711
919/541-5595

William Ellison
Director
Ellison Consultants
4966 Tall Oaks Drive
Monrovia, MD 21770-9316
301/865-5591

Thomas E. Emmel
Senior Chemical Engineer
Radian Corporation
3200 E. Chapel Hill Road
P.O. Box 13000
Research Triangle Park, NC 27711
919/541-9100

David S. Ensor
Dir., Center for Aerosol Technology
Research Triangle Institute
P.O. Box 12194
Research Triangle Park, NC 27709
919/541-6735

Robert Erdmann
Engineer
Coen Company
1510 Rollins Road
Burlingame, CA 94010
415/697-0440

Michael Esche
President
Saarber-Hoelter Shu
Hafenstrasse 6
D-66 Saarbruecken
FEDERAL REPUBLIC OF GERMANY
N/A

David Eskinazi
Project Manager
Electric Power Research Institute
P.O. Box 10412
Palo Alto, 94303
415/855-2198

Robert J. Farrauto
Research Manager
Engelhard Corporation
Menlo Park
Edison, NJ 08818
201/321-5306

Hamid Farzan
Research Engineer
Babcock & Wilcox
1562 Beeson Street
Alliance, OH 44601
216/821-9110 X385

Caruso Filippo
Chief Power Plant Engineer
ENEL
Venice - Fusina Power Plant
ITALY
N/A

Timothy O. Flora
Plant Superintendent
Ohio Edison Company
200 Oberlin Avenue
Lorain, OH 44052
216/244-1991 X250

Albert O. Flowers
Operations & Maintenance Manager
Carolina Power & Light Company
P.O. Box 1238
Roxboro, NC 27573
919/599-1174

James D. Freihaut
Research Scientist
United Technologies Res. Center
Silver Lane, MS-30
East Hartford, CT 06108
203/727-7427

Donald J. Frey
Manager, Product Engineering
TRW
Space & Technology Group
One Space Park (R4-2004)
Redondo Beach, CA 90278
213/535-8251

Stephen S. Frey
Generating Station Engrng. Spvsr.
Wisconsin Power & Light Company
222 W. Washington Avenue
Madison, WI 53701
608/252-3348

Yuan Fu
Chemical Engineer
U.S. Department of Energy
P.O. Box 10940
Pittsburgh, PA 15236
412/675-6065

Rosemary Furfey
Senior Planner
Mass. Dept. Envrnmntl Qlty Eng.
1 Winter Street, 8th Floor
Boston, MA 02108
617/292-5762

Gerald M. Gardetta
Environmental Affairs Administrator
Southern California Gas Company
810 South Flower Street
Los Angeles, CA 90017
213/689-3365

Robert P. Gehri
Senior Research Specialist
Southern Company Services
P.O. Box 2625
Birmingham, AL 35202
205/870-6720

William G. Gillespie
N/A
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585
202/586-9850

Dan V. Giovanni
Consultant
Electric Power Technologies
P.O. Box 5560
Berkeley, CA 94705
415/653-6422

Philip M. Goldberg
Mechanical Engineer
Pittsburgh Energy Technology Center
P.O. Box 10940
Pittsburgh, PA 15236
412/675-5882

Klaus Goldschmidt
Department Head
VEBA Kraftwerke Ruhr AG
Postfach 10 01 25
D-4650 Gelsenkirchen
FEDERAL REPUBLIC OF GERMANY
0209/601-5851

John P. Gooch
Associate Director
Southern Research Institute
P.O. Box 55305
Birmingham, AL 35255-5305
205/323-6592

Glenn E. Goodman
Manager, Business Development/Power
Ford Bacon & Davis
P.O. Box 38209
Dallas, TX 75238-0209
214/238-6500

Toby R. Gouker
Research Engineer
W. R. Grace & Company
7379 Route 32
Columbia, MD 21044
301/531-4131

Charles W. Graham
Energy Development
Self-Employed
9 Alhambra Court
Antioch, CA 94509
415/754-3749

Joseph Greco
Utility Sales Manager
The Taulman Sales Company
P.O. Box 52383
Atlanta, GA 30355
404/261-2535

Gary J. Green
Research Chemist
Mobil Research & Development Corp.
Central Research Laboratory
P.O. Box 1025
Princeton, NJ 08540
609/737-4901

George P. Green
Manager, Production Services
Public Service Company of Colorado
1800 West Sheri Lane
Littleton, CO 80120
303/797-4122

Jack Greene
Administrative Officer
U.S. EPA
MD-49
Research Triangle Park, NC 27711
919/541-2905

Philip A. Gristwood
Head, Combustion Technology Group
Babcock Energy, Ltd.
165 Great Dover Street
London SEI 4YB
ENGLAND
01/407-8383

D. J. Groves
Manager, Engineering & Resources
Public Service Co. of New Mexico
Alvarado Square, MS-0316
Albuquerque, NM 87158
505/768-6632

Sigurd Hagen
Principal Engineer
State Pollution Control Authority
P.B. Box 8100 DEP.
N-0032 OSL01
NORWAY
47 2 659810

Charles S. Hakkarinen
Technical Manager
Electric Power Research Institute
P.O. Box 10412
Palo Alto, CA 94303
415/855-2592

Robert E. Hall
Chief, Combustion Research Branch
U.S. EPA
MD-65
Research Triangle Park, NC 27711
919/541-2477

Leslie C. Hardison
President
ARI Technologies
600 N. First Bank Drive
Palatine, IL 60067
312/359-7810

Hiroshi Hashida
N/A
James D. Wolfensohn Company
425 Park Avenue
New York City, NY 10022
212/909-8164

Gregory J. Haussman
Research Assistant
Stanford University
Dept. of Mechanical Engineering
Stanford, CA 94305
415/723-1823

Todd D. Hellewell
Principal Engineer
Combustion Engineering
1000 Prospect Hill Road
Windsor, CT 06095
203/285-4919

Eric R. Hennen
Environmental Engineer
Dairyland Power Cooperative
2615 East Avenue, S.
Lacrosse, WI 54601
608/787-1371

David S. Henzel
Senior Engineer
Burns & Roe Services Corporation
P.O. Box 18288
Pittsburgh, PA 15236
412/675-4672

Bo Herrlander
Manager
Flakt Industri AB
Research and Development
Air Pollution Control
S-351 87 Vaxjo, SWEDEN
0470/87623

Sven E. Hetager
Senior Engineer
State Power Board
P.O. Box 5091 Maj.
N-0301)SL03
NORWAY
+47 2 469800

Andrew A. Hetz
Associate Engineer
Virginia Power Company
5000 Dominion Boulevard
Glen Allen, VA 23060
804/273-0135

Richard M. Himes
Engineer
Fossil Energy Research Corporation
23342 C South Pointe
Laguna Hills, CA 92653
714/859-4466

Charles C. Hong
Senior Research Engineer
Columbia Gas System Service Corp.
1600 Dublin Road
P.O. Box 2318
Columbus, OH 43216-2318
614/481-1454

Vincent Huang
Project Manager
A. O. Smith Corporation
12100 W. Park Place
P.O. Box 23994
Milwaukee, WI 53223-0994
414/359-4255

Allen Hubbard
Environmental Engineer
WI Department of Natural Resources
Dureau of Air Management
P.O. Box 7921
Madison, WI 53707
608/266-3450

Wilfred S. Hung
Manager
Solar Turbines, Inc.
2200 Pacific Highway
P.O. Box 85376
San Diego, CA 92138-5376
619/544-5095

Boyd E. Hurst
Engineering Associate
Exxon Research & Engineering Co.
P.O. Box 101
Florham Park, NJ 07853
201/765-6917

Ivan V. Insua
Supervisory Engineer
Salt River Project
P.O. Box 52025
Phoenix, AZ 85072-2025
602/236-5240

Reda S. Iskandar
Project Manager
Corning Glass Works
33 W. Denison Parkway
Corning, NY 14831
607/974-7306

Takusuke Izumi
Manager
Anritsu Electric Company
1800 Onna Atsugi City
Kanagaa, JAPAN 243
0462/231111

Keijo K. Jaanu
N/A
Kemira Oy Vuorikemia
P.O. Box 36
SF-28840 PORI
FINLAND
35839 443 555

Benjamin W. Jackson
N/A
Black & Veatch
1500 Meadow Lake Parkway
Kansas City, MO 64114
913/339-2000

Joseph J. Janush
Vice President & General Manager
KVB
18006 Skypark, S.
Irvine, CA 92714
714/250-6314

Kevin Johnson
Senior Engineer
Radian Corporation
3200 E. Chapel Hill Road
Research Triangle Park, NC 27709
919/541-9100

Stephen Johnson
Mgr., Applied Combustion Technology
Physical Sciences
P.O. Box 3100
Andover, MA 01810
617/475-9030

Dale G. Jones
Manager, Process Engineering
Emcotek-Btu
8220 Doe Avenue
Visalia, CA 93291
209/651-2000

Gary D. Jones
Program Manager
Radian Corporation
P.O. Box 13000
Research Triangle Park, NC 27704
919/541-9100

Steve M. Katzberger
Supervisor, Emission Control
Sargent & Lundy
55 East Monroe Street
Chicago, IL 60603
312/269-6672

Robert F. Kaupp
Sales Manager
Johnson Matthey Company
436 Devon Park Drive
Wayne, PA 19087
215/341-8502

Michael Kavanaugh
Economist
Self-Employed
4015 Benton Street, N.W. #4
Washington, DC
202/965-3455

Mark Kawashima
Representative
NGK Insulators
New York Liaison Office
3 Pickwick Plaza
Greenwich, CT 06830
203/869-9555

Robert E. Kenson
Development Director
Met-Pro Corporation
P.O. Box 144
Harleysville, PA 19438
215/723-6751

Mary Kentgens-Baggbn
Senior Engineer
Ministry of Economic Affairs
Bezuidenhourse Weg #6, Rm. 012
2594 AV, The Hague
THE NETHERLANDS
N/A

Stephen E. Kerho
Consultant
Electric Power Technologies
25108 Marguerite Parkway, B-239
Mission Viejo, CA 92691
714/380-7316

Mark J. Khinkis
Mgr., Applied Combustion Research
Institute of Gas Technology
4201 W. 36th Street
Chicago, IL 60632
312/890-6445

Takashi Kiga
Engineer
Ishikawajima-Harima Heavy Ind.
Toyo Office 30-13
5-chome, Toyo
Koto-ku, Tokyo 135 JAPAN
03/699-2682

James D. Kilgroe
Mechanical Engineer
U.S. EPA
MD-49
Research Triangle Park, NC 27711
919/541-2854

J. L. King
Deputy Thermal Development Manager
Babcock Energy, Ltd.
Research Center
High Street, Renfrew PA4 8UW
Strathclyde, SCOTLAND
041-886-2201

Lawrence P. King
Senior Marketing Specialist
Babcock & Wilcox
1562 Beeson Street
Alliance, OH 44601
216/821-9110

Karl Knoblauch
General Manager
Bergbau-Forschung GmbH
Franz-Fischer-Weg 61
D-4300 Essen 13
FEDERAL REPUBLIC OF GERMANY
0201/105-9225

Bernard J. Koch
Director, Project Development
Conoco Coal Research
4000 Brownsville Road
Library, PA 15129
412/854-6612

Angelos Kokkinos
Mgr., Fuel Systems Development
Combustion Engineering
1000 Prospect Hill Road
Windsor, CT 06095
203/285-4328

David P. Kreimer
Senior Production Engineer
Missouri Public Service
10700 East 350 Highway
Kansas City, MO 64138
816/737-9340

Hal M. Kruger
Senior Engineer
Cleveland Electric Illuminating Co.
P.O. Box 5000
Cleveland, OH 44101
216/622-9800 X3146

Reiner W. Kuhr
Project Engineer, Adv. Technologies
Stone & Webster Engineering Corp.
245 Summer Street
Boston, MA 02107
617/589-2823

James S. Kulig
Manager, Utility Projects
Babcock & Wilcox
20 S. Van Buren Avenue
Barberton, OH 44203
216/860-6370

F. R. Kurzynske
Mgr., Combustion Emission Control
Gas Research Institute
8600 West Bryn Mawr
Chicago, IL 60631
312/399-8203

W. S. Lanier
Manager, Eastern Operations
Energy & Envrnmntl. Research Corp.
800 Eastowne Drive, Suite 203
Chapel Hill, NC 27514
919/489-1726

Leonard N. Lapatnick
Environmental Research Engineer
PSE&G Research Corporation
80 Park Plaza, T16A
Newark, NJ 07101
201/430-8129

Dorothy P. Lau
Design Engineer
Ontario Hydro
700 University Avenue, H10 E3
Toronto, Ontario
CANADA M5G 1X6
416/592-7306

Catherine Laughlin
Business Analyst
Fuel Tech
61 Taylor Reed Place
Stamford, CT 06906
203/359-1320

Albert D. LaRue
Section Mgr., Combustion Systems
Babcock & Wilcox
20 S. Van Buren
Barberton, OH 44203
216/860-1493

G. K. Lee
Mgr., Combustion & Carbonization
Energy Mines & Resources Canada
555 Booth Street
Ottawa Ontario
CANADA K1A 0G1
613/996-4570 X222

David J. Lehtola
Application Engineer
Cleaver Brooks Div. of Aqua Chem
3707 N. Richards Street
Milwaukee, WI 53201
414/961-2856

Rainer Leibfritz
Engineer
University of Karlsruhe
Hertzstrasse 16
D-7500 Karlsruhe
FEDERAL REPUBLIC OF GERMANY
0721/608-4565

Charles C. Leivo
Vice President, Marketing
Dresser Industries
Lodge-Cottrell Division
601 Jefferson, Room 2720
Houston, TX 77002
713/750-2091

Bill A. Leonardi
Sales Engineer
Corning Glass Works
MP 8-5-1, Industrial Ceramics
Corning, NY 14830
607/974-7115

George R. Lester
Senior Research Scientist
Allied Signal
50 East Algonquin Road
Des Plaines, IL 60017-5016
312/391-3314

Thomas W. Lester
Professor & Chairman
Louisiana State University
Dept. of Mechanical Engineering
Baton Rouge, LA 70830
N/A

Frank Liao
Associate Engineer
Mobil Research & Development
P.O. Box 1026
Princeton, NJ 08540
609/737-4955

Robert A. Lisauskas
Director, Research & Development
Riley Stoker Corporation
45 McKeon Road
Worcester, MA 01610
617/792-4801

Douglas P. Litwiller
Performance Engineer
Iowa Electric Light & Power Company
East Main Street Road
Marshallowtown, IA 50158
515/754-5845

David C. Livengood
Environmental Technology Coord.
Argonne National Laboratory
9700 S. Cass Avenue, Bldg. 362
Argonne, IL 60439
312/972-3737

Steve B. Londerville
Staff Engineer
Coen Company
1510 Rollins Road
Burlingame, CA 94010
415/697-0440

Phillip A. Lowe
President
Intech
11316 Royen Drive
Potomac, MD 20854
301/983-9367

H. H. Lulf
Director Production
Amsterdam Power Company
c/o Royal Schelde, P.O. Box 16
4380 AA Vlissingen
THE NETHERLANDS
31/1184-82414

Richard K. Lyon
N/A
Energy & Envrnmntl. Research Corp.
1090 King George's Post Road
Edison, NJ 08837
201/225-1300

Timothy Ma
Senior Engineer
CE Canada Power Systems
99 Bank Street
Ottawa, CANADA K1P 6C5
613/560-4702

Mike G. Malloy
Associate Editor
Coal & Synfuels Technology
1401 Wilson Boulevard, Suite 910
Arlington, VA 22209
703/528-1244

Louis J. Manfred, II
Mgr., Advanced Ceramic Development
Corning Glass Works
SP DV-2-1
Corning, NY 14831
607/974-3906

Rene Mangel
Engineer
Ontario Hydro Research Division
800 Kipling Avenue
Toronto, Ontario
CANADA M8Z 5S4
416/231-4111

M. N. Mansour
President
Applied Utility Systems
1720 E. Garry Avenue, Suite 221
Santa Ana, CA 92705
714/261-8671

Elio Marchesi
N/A
ENEL Unita Laboratorio
Via Nino Bixio 39
29100 Piacenza
ITALY
N/A

Earl Marcus
Chemical Engineer
Tennessee Valley Authority
2N 77A Missionary Ridge Place
Chattanooga, TN 37401
615/751-5638

Gerry Maringo
Development Engineer
Babcock & Wilcox
20 S. Van Buren Avenue
Barberton, OH 44203
216/860-6321

John L. Marion
Senior R&D Engineer
Combustion Engineering
P.O. Box 500
Windsor, CT 06095
203/285-4539

Gianni Mascalzi
Engineer
Ansaldo Componenti
Viale Sarza 336
Milan, ITALY 20126
216/860-6029

John S. Maulbetsch
Sr. Program Manager
Electric Power Research Institute
P.O. Box 10412
Palo Alto, CA 94303
415/855-2438

James D. Maxwell
Chemical Engineer
Tennessee Valley Authority
501 Chemical Engineering Bldg.
Muscle Shoals, AL 35661
205/386-3060

Mallory S. May
Owner
Professional Services & Management
703 McKinney Avenue
Suite 302
Dallas, TX 75202
214/954-1081

Manville Mayfield
Branch Chief
Tennessee Valley Authority
2N 51A Missionary Ridge Place
Chattanooga, TN 37401
615/751-7458

James M. McCarthy
Research Engineer
Energy & Envrnmntl. Corporation
8001 Irvine Boulevard
Santa Ana, CA 92705
714/552-1803

Barry L. McDonald
Vice President and General Manager
Energy Systems Associates
15991 Red Hill Avenue, Suite 110
Tustin, CA 92680-7388
714/259-9520

Mike McElroy
Subprogram Manager
Electric Power Research Institute
P.O. Box 10412
Palo Alto, CA 94303
415/855-2471

Claire E. McHale
Group Leader, R&D
Riley Stoker Corporation
45 McKeon Road
Worcester, MA 01610
617/792-4802

Marilyn McIlvane
Managing Editor
McIlvane Company
2970 Maria
Northbrook, IL 60062
312/272-0010

Robert W. McIlvane
President
McIlvane Company
2970 Maria
Northbrook, IL 60062
312/272-0010

Alain Milhau
Head, Air Control Pollution Dept.
Agency for the Quality of Air
Tour Gan Cedex 13
92082 Paris la Defense 2
Paris, FRANCE
N/A

Scott A. Miller
Staff Engineer
Dayton Power & Light Company
P.O. Box 468
Aberdeen, OH 45101
513/549-2641

Jim Moll
President
SFA Pacific
444 Castro Street, Suite 920
Mountain View, CA 94041
415/969-8876

Tami A. Montgomery
Research Assistant
University of California Irvine
Combustion Lab
Dept. of Mechanical Engineering
Irvine, CA 92717
714/856-4994

Keith A. Moore
Marketing & Business Development
Dykema Engineering
5850 Canoga Avenue, Suite 400
Woodland Hills, CA 91367
818/712-0070

Shigeki Morita
Leader, Combustion Systems
Babcock-Hitachi
Combustion Systems
6-9 Takarmachi, Kure City
Hiroshima 737, JAPAN
0823/21-1161 X338

Dominick J. Mormile
Manager, Air Quality
Consolidated Edison Co. of New York
4 Irving Place
New York, NY 10003
212/460-6275

James A. Mulholland
Project Officer
U.S. EPA
AEERL MD-65
Highway 54 & Alexander Drive
Research Triangle Park, NC 27711
919/541-7663

Albert J. Muller
Project Engineer
Engelhard Corporation
2655 U.S. Route 22
Union, NJ 07083
201/964-2701

Lawrence J. Muzio
Vice President
Fossil Energy Research Corporation
23342 C South Pointe
Laguna Hills, CA 92653
714/859-4466

Osamu Naito
Combustion Engineering Secretary
Mitsubishi Heavy Industries
Nagasaki Ship Yard & Engine Works
1-1, Akunoura-Machi
Nagasaki, JAPAN
0958-62-8021

Lewis G. Neal
President
NOXSO Corporation
P.O. Box 586
Library, PA 15129
412/675-6293

Robert L. Nebeker
Senior Engineer
Westinghouse Idaho Nuclear Company
P.O. Box 4000
Idaho Falls, ID 83403
208/526-3578

Peter Necker
Head, Environment Department
Neckarwerke Elek. AG
Neckarwerke, Abteilung Umwelt.
7300 Esslingen, Kuferstrasse 2
WEST GERMANY
49/711-3190-3071

James H. Nelson
Project Engineer II
Nevada Power Company
6226 W. Sahara
Las Vegas, NV 89102
702/367-5685

Kirsten K. Nielsen
Chemical Engineer
A/S Niro Atomizer
Gladsaxevej 305
DK 2860 Soeborg
DENMARK
45/169-1011

Per Nielsen
Chemical Engineer
Danish Boiler Owners Association
Gladsaxe Mallevei 15
Soeborg, DK 2860
DENMARK
009/45 1 69 6511

James H. Nylander
Senior Engineer
San Diego Gas & Electric Company
P.O. Box 1831
San Diego, CA 92112
619/696-4906

John O'Leary
Project Engineer
Fuel Tech
61 Taylor Reed Place
Stamford, CT 06906
203/359-1320

Ulf Oesterlund
Operation Manager
Stockholm Energy
Stockholm Box 4454
Stockholm
SWEDEN
8-380100

George Offen
Project Manager
Electric Power Research Institute
P.O. Box 10412
Palo Alto, CA 94303
415/855-8942

Luigi G. Oldrini
Resident Representative
Franco Tosi Industriale
c/o Westinghouse Electric Co.
The Quadrangle
Orlando, FL 32826
305/282-2264

Kenneth R. Olen
Technical Specialist
Florida Power & Light Company
P.O. Box 14000
Juno Beach, FL 33408-0420
305/694-3604

Earl D. Oliver
Principal Engineer
Oliver Associates
2049 Kent Drive
Los Altos, CA 94022
415/964-4838

Jim R. Ortamond
Senior Project Engineer
Ford, Bacon & Davis
P.O. Box 38209
Dallas, TX 75238
214/238-6679

Bo Oscarsson
Program Manger
Gotaverken Energy Ssytems
8008 Corporate Circle Drive
Charlotte, NC 28211
704/541-1453

Ronald G. Ostendorf
Section Head
Proctor & Gamble Company
6110 Center Hill Road
Cincinnati, OH 45224
513/659-7022

Joseph H. Oxley
Program Manager
Battelle
505 King Avenue
Columbus, OH
614/424-7885

Birgitta Palmberger
Chemcial Engineer
National Energy Admin. (Sweden)
S11787 Stockholm
SWEDEN
+46/8 744 9500

Y. S. Pan
N/A
Pittsburgh Energy Technology Center
P.O. Box 10940
Pittsburgh, PA 15236
412/675-5736

Andy S. Paranjape
Senior Project Engineer
Kerr-McGee
P.O. Box 25861
Oklahoma City, OK 73125
405/270-2906

Craig Parker
Sr. Environmental Engineer
Iowa Electric Light & Power Co.
P.O. Box 351
Cedar Rapids, IA 52406
319/398-4675

Satyan Patel
N/A
James D. Wolfensohn
425 Park Avenue
New York, NY 10022
212/909-8177

David W. Pearsall
Product Manager
Combustion Engineering
1000 Prospect Hill Road
Windsor, CT 06095
203/285-5127

Robert R. Pease
Spvsr., Air Quality Engineering
South Coast Air Quality Mgmnt. Dist
9150 Flair Drive
El Monte, CA 91731
818/572-6174

Earl Pedersen
Engineer
Burmeister Wain Energi
Teknikerbyen 23
Dk-2830 Virum
DENMARK
45/285-7110

Richard M. Pena
Superintendent of Plant Betterment
City Public Svc. Bd. of San Antonio
P.O. Box 1771
San Antonio, TX 78296
512/227-3211 X3313

Michael Perlsweig
Mgr., Flue Gas Cleanup Program
U.S. Department of Energy
Fossil Energy, FE-23
Washington, DC 20545
301/353-4399

John Perry
Environmental Engineer
New Jersey Dept. of Envrnmt. Prot.
401 E. State Street
Trenton, NJ 08625
609/984-3023

Robert A. Perry
N/A
Sandia National Labs
Organization 8353
Livermore, CA 94550
415/422-2298

David W. Pershing
Assistant to President
Energy & Envrnmntl. Research Corp.
University of Utah
310 Park Building
Salt Lake City, UT 84112
801/581-6925

Karen K. Pesson
Environmental Program Specialist
Department of Environmental Quality
P.O. Box 44096
Baton Rouge, LA 70404
504/342-8942

Wallace Pitts
Associate
Killzelly Environmental Associates
P.O. Box 31265
Raleigh, NC 27622
919/781-3150

Al R. Plantz
Electronic Engineer
U.S. Department of Energy
P.O. Box 10940
Pittsburgh, PA 15236
412/675-5725

Everett L. Plyler
Dir., Combustion & Indoor Air Div.
U.S. EPA
MD-54
Research Triangle Park, NC 27711
919/541-2918

J. H. Pohl
Director, Research & Development
Energy Systems Associates
15991 Red Hill Avenue, Suite 110
Tustin, CA 92689-7388
714/259-9520

Terry Poles
Product Manager
Engelhard Corporation
2655 U.S. Route 22
Union, NJ 07083
201/964-2831

James E. Poston
Asst. Chief, Tech. Scvs. Br.
Tennessee Valley Authority
BR 2N 45A
Chattanooga, TN 37402-2801
615/751-2774

Ken R. Price
Group Leader
Proctor & Gamble Company
Energy & Safety Systems Dept.
6110 Center Hill Road, FB 1N15
Cincinnati, OH 45224
513/659-7877

Singgih Pujono
Environmental Specialist
Mississippi Power & Light Company
P.O. Box 1640
Jackson, MS 39205
601/969-2533

B. B. Pypker
General Manager, New Projects
Amsterdam Power Company
c/o Royal Schelde, P.O. Box 16
4380 AA Vlissingen
THE NETHERLANDS
31/1184-82414

Greg C. Quartucy
Principal Engineer
KVB
18006 Skypark Boulevard
Irvine, CA 92714
714/250-6226

Jay A. Ratafia-Brown
Director, Fossil Energy Projects
Science Applications International
1710 Goodridge Drive
P.O. Box 1303, T6-1
McLean, VA 22102
703/448-6343

Otto Rentz
Professor/Institute Director
University of Karlsruhe
Institute for Industrial Production
Hertzstrasse 16, 7500 Karlsruhe 21
FEDERAL REPUBLIC OF GERMANY
721/608-4460 X4569

James P. Riley
Maintenance Engineer
Delmarva Power
P.O. Box 408
Millsboro, DE 19966
302/934-9211

David H. Robertson
Dir., Sales & Business Development
Combustion Engineering
1000 Prospect Hill Road
Windsor, CT 06095
203/285-9161

Tommy R. Robinson
Operating Supervisor
Carolina Power & Light Company
P.O. Box 1238
Roxboro, NC 27573
919/599-1174

Erik Rosenberg
N/A
Elkraft Power Company, Ltd.
5, Lautruphoej
2750 Ballerup
DENMARK
+45-2-66-00-22

Harvey S. Rosenberg
Senior Reserch Engineer
Battelle Columbus
505 King Avenue
Columbus, OH 43201-2693
614/424-5010

Carlo Rossi
Engineer
National Electricity Gen. Board
Via C. Bathsti 69
56100 Pisa
ITALY
050/501063

Edward Rubin
Professor
Carnegie-Mellon University
Dept. of Mechanical Engineering
Pittsburgh, PA 15213
412/268-2491

Norman C. Samish
Staff Research Engineer
Shell Development Company
P.O. Box 1380
Houston, TX 77251
713/493-7944

Bell Sample
Consulting Engineer
Houston Lighting & Power Company
12301 Kurland Drive
Houston, TX 77034
713/481-7595

Gail R. Santoro
Business Development
Johnson Matthey
436 Park Drive
Wayne, PA 19807-1816
215/341-8500

Malcolm Sarjeant
Head, Combustion Section
Central Electricity Gen. Board
Marchwood Eng. Labs
Marchwood, Southhampton
S04 4ZB, UNITED KINGDOM
0703/865711 X492

Giancarlo Scavizzi
Engineer
Ansaldo Componenti
Viale Sarza 336
Milan, ITALY 20126
2/6045 2205

C. Scheffers
Engineering Manager
Royal Schelde
P.O. Box 16
4380 AA Vlissingen
THE NETHERLANDS
31/1184-82414

Olaf B. Schubee
Managing Director
NOXERAM
Senefelderstrasse 15
D-5060 Bergisch Gladbach 2
Bundersrepublik, WEST GERMANY
011/49 02202 1203 30

Herbert Schuster
Engineer
Deutsche Babcock Werke
Duisburger Strasse 375
4200 Oberhausen 1
WEST GERMANY
208/833-2853

Charles B. Sedman
Chemical Engineer
U.S. EPA
Research Triangle Park, NC 27711
919/541-7700

James R. Sexton
Consulting Engineer
Armco
P.O. Box 600
Middletown, OH 45043
513/425-2556

Todd W. Shaw
Engineer
City of Austin
Generation Engineering Division
1524 So. IH 35, Suite 225
Austin, TX 78767
512/440-5635

Noboru Shinozuka
Engineer
Babcock-Hitachi
501 Red Rock Drive
Wadsworth, OH 44281
216/860-6669

George Shulof
Pres. and Chief Operating Officer
Fuel Tech
61 Taylor Reed Place
Stamford, CT 06906
203/359-1320

Jack S. Siegel
Deputy Assistant Secretary
U.S. Department of Energy
Germantown, MD 20585
301/353-3991

William L. Silence
Research Associate
Haynes International
1020 W. Park Avenue
Kokomo, IN 46901
317/456-6201

Berman K. Sipe
System Environmentalist
Duke Power Company
P.O. Box 33189
400 South Tryon Street
Charlotte, NC 28242
704/373-4436

Terry Skidmore
Senior Chemical Engineer
Arizona Public Service
P.O. Box 53999, MS-5120
Phoenix, AZ 85072
602/371-7465

Lowell Smith
Program Manager
U.S. EPA
RD-680
Washington, DC 20460
202/382-5717

Lowell L. Smith
Vice President
Energy Technology Consultants
2091 Business Center Drive, #100
Irvine, CA 92715
714/833-2523

Leo Snepvangers
Engineer
Netherlands Energy Research
Foundation (ECN)
P.O. Box 1, 1755 ZG Petten
THE NETHERLANDS
0/2246-4248

Robert J. Snodgrass
Senior Research Engineer
Riley Stoker Corporation
P.O. Box 2040
Worcester, MA 01613-2040
617/792-4814

Arun V. Someshwar
Assistant Professor
University of New Hampshire
Department of Chemical Engineering
Durham, NH 03824
603/867-2298

Heinz Spliethoff
Engineer
Saarbergwerke AG
Tricrerstrase 1
D-6600 Saarbrucken
FEDERAL REPUBLIC OF GERMANY
0681/405-3805

Mark T. Staniulis
Staff Chemist
Union Carbide
Old Sawmill River Road
Tarrytown, NY 10581
914/789-3865

Joseph P. Strakey
Deputy Director, PETC
U.S. Department of Energy
P.O. Box 10940
Pittsburgh, PA 15236
412/675-6125

Ken M. Sullivan
Technical Advisor
Coal & Allied Industries
19th Level, Goldfields House
1 Alfred Street, G.P.O. Box 1554
Sydney 2000, AUSTRALIA
02/233-4122

Kohei Suyama
Manager, Windsor Technical Office
Mitsubishi Heavy Industries America
c/o Combustion Engineering
1000 Prospect Hill Road
Windsor, CT 06095
203/688-1911 X2491

Maciej Szczawnicki
Science Counselor
Embassy of Poland
2640 16th Street, N.W.
Washington, DC 20009
202/234-3800

Thomas Szymanski
Manager Product Research
Norton Company
P.O. Box 350
Akron, OH 44309
216/673-5860

David L. Tackett
Senior Engineer
Ohio Edison Company
76 South Main Street
Akron, OH 44308
216/384-5741

Masaki Takahashi
Project Manager/Liaison Engineer
Electric Power Research Institute
P.O. Box 10412
Palo Alto, CA 94303
415/855-2777

Thomas D. Tarnok
Product Sales Manager
Joy Manufacturing Company
Western Precipitation Division
4565 Colorado Boulevard
Los Angeles, CA 90039
818/240-2300

Billy Tauzin
Congressman
Congressman -- Louisiana
P.O. Box 1987
Thibodaux, LA 70302
504/447-1987

Donald P. Teixeira
Technical Manager
Pacific Gas & Electric Company
3400 Crow Canyon Road
San Ramon, CA 84583
415/866-5531

Thomas R. Thomas
Fellow Scientist
Westinghouse Idaho Nuclear Company
P.O. Box 4000
Idaho Falls, ID 83403
208/526-3086

Paul F. Thompson
President
Tenerx Corporation
P.O. Box 1444
Friendswood, TX 77546
713/482-5801

Richard E. Tischer
Project Manager
U.S. Department of Energy
P.O. Box 10940
Pittsburgh, PA 15236
412/831-6195

Michael Tomann-Rosos
Engineer
IFO Electric
Porzellanfabrik Frauenthal
A 8523 Frauental
AUSTRIA
03462-2000

Richard S. Topor
International Reg. Mgr., Licensing
Combustion Engineering
1000 Prospect Hill Road
Windsor, CT 06095
203/285-9934

Majed A. Toqan
Research Engineer
Massachusetts Inst. of Technology
60 Vassar Street, Bldg. 31-261
Cambridge, MA 02139
617/253-1721

Richard H. Tourin
Consultant
Tourin Associates
195010A 67th Avenue
Flushing, NY 11365
718/454-2839

Linh Tran
Environmental Engineer
U.S. EPA -- Region 9
215 Fremont Street
San Francisco, CA 94105
415/974-7631

Antonio Traverso
Engineer
Ansaldo Componenti
Research & Development Office
Via Pacinotti, 20
Genova, ITALY 16151
010/4103-2177

Edward C. Trexler
Program Manager
U.S. Department of Energy
Washington, DC 20545
301/353-2683

Stephen M. Turner
Product Manager
Norton Company
9888 Bissonnet #480
Houston, TX 77036
713/988-8008

Donald Urwin
N/A
Tioxide Group
Portrack Lane
Stockton-on-Tees
Cleveland, UNITED KINGDOM
N/A

James M. Valentine
Vice President, Marketing
Fuel Tech
61 Taylor Reed Place
Stamford, CT 06906
203/359-1320

L. A. Van Gelder
General Manager
Royal Schelde
P.O. Box 16
4380 AA Vlissingen
THE NETHERLANDS
31/1184-82414

Joel Vatsky
Dir., Combustion & Envrnmntl. Sys.
Foster Wheeler Energy Corporation
110 South Orange Avenue
Livingston, NJ 07039
201/533-2105

Gary R. Veerkamp
Senior Mechanical Engineer
Pacific Gas & Electric Company
77 Beale Street, Room 2555
San Francisco, CA 94106
415/972-1576

Jan L. Vernon
Environment Team Leader
IEA Coal Research
14-15 Lower Grosvenor Place
London, SWIW 0E2
UNITED KINGDOM
01/828-4661

John Veurink
Engineer
Stork Boilers
P.O. Box 20, 7550 GB
Hengelo
THE NETHERLANDS
074/454321

Richard T. Waibel
Mgr., Technical Dept., Burner Div.
John Zink Company
4401 S. Peoria
Tulsa, OK 74105
918/747-1371

Ali Wali
Program & Planning Analyst
Public Service Commission
4802 Sheboygan Avenue
Madison, WI 53702
608/267-3594

John H. Wasser
Research Chemical Engineer
U.S. EPA
AEERL, MD-65
ERC Building G323
Research Triangle Park, NC 27711
919/541-2476

Larry Waterland
Program Manager
Acurex Corporation
485 Clyde Avenue
Mountain View, CA 94039
415/961-5700

Greg F. Weber
Research Supervisor
Energy Research Center
P.O. Box 8213, University Station
Grand Forks, ND 58202
701/777-5222

Bruce Weinstein
Technical Project Manager
Research Cottrell
P.O. Box 1500
Somerville, NJ 08876
201/685-4894

Alexander Weir, Jr.
Chief Research Scientist
Southern California Edison
P.O. Box 800
2244 Walnut Grove Avenue
Rosemead, CA 91770
818/302-2785

Chandler H. Wells
Manager, Marine Contract Sales
Combustion Engineering
1000 Prospect Hill Road
Windsor, CT 06095
203/285-9163

David L. Williams
Product Manager
United Catalysts
P.O. Box 32370
Louisville, KY 40214
502/634-7260

Johan G. Witkamp
Engineer
N. V. Kema
Utzechtseweg 310
6812 AR Arnhem
HOLLAND
085/563625

Alan D. Witwer
Product Manager
John Zink Company
4401 S. Peoria Avenue
Tulsa, OH 74105
918/747-1371 X2136

John Worley
Environmental Engineer
St. Johns River Power Park
P.O. Box 26888
Jacksonville, FL 32218
904/751-7720

Hitoshi Yamazaki
Mgr., Technical Cooperation Group
Mitsubishi Heavy Industries
5-1 Marunouchi, 2-chome
Chiyoda-ku, Tokyo
JAPAN
03/212-3111

Charles Yee
Chemical Engineer
NEESA
Port Hueneme, CA 93403-5014
805/982-4747